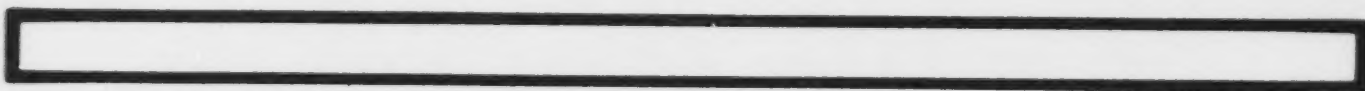
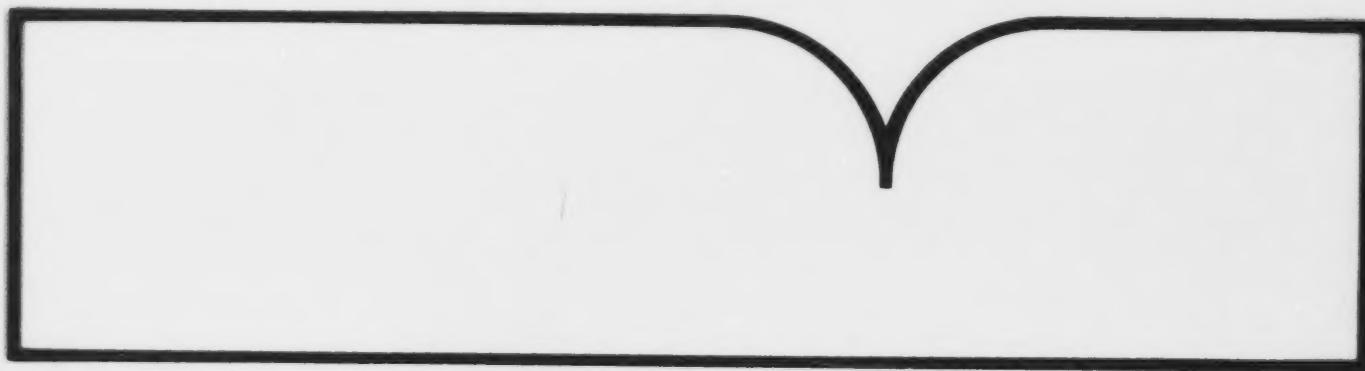


PB88-137534

Fossil and Nonfossil Fueled-Fired
Industrial Boilers
Background Information for Promulgated SO₂
Standards. Volume 4

(U.S.) Environmental Protection Agency
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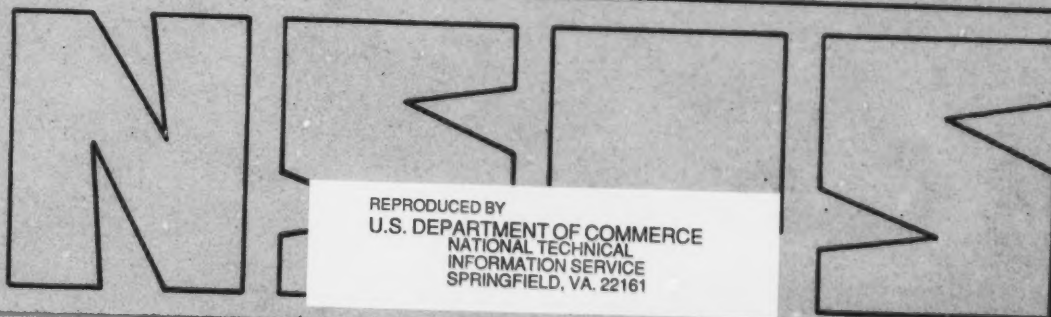
Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-450/3-87-024
September 1987

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Fossil and Nonfossil Fueled-Fired Industrial Boilers — Background Information for Promulgated SO₂ Standards Volume 4



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Industrial Boilers — Background
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Emission Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
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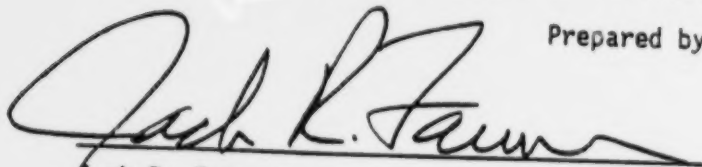
September 1987

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ENVIRONMENTAL PROTECTION AGENCY

Background Information Document
for New Industrial-Commercial-Institutional Steam Generating Units

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12/1/87
(Date)

1. The standards of performance would limit emissions of sulfur dioxide from new coal- and oil-fired industrial-commercial-institutional steam generating units larger than 29 MW (100 million Btu per hour). Particulate emissions from new oil-fired industrial-commercial-institutional steam generating units in this same size category are also limited. Section 111 of the Clean Air Act (42 U.S.C. 7411), as amended, directs the Administrator to establish standards of performance for any category of new stationary source of air pollution that "... causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."
2. Copies of this document have been sent to the following Federal Departments: Office of Management and Budget, Commerce, Interior, and Energy; the National Science Foundation; and the Council on Environmental Quality. Copies have also been sent to members of the State and Territorial Air Pollution Program Administrators; the Association of Local Air Pollution Control Officials; EPA Regional Administrators; and other interested parties.
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1.0 SUMMARY

On June 19, 1986, the Environmental Protection Agency (EPA) proposed standards of performance limiting emissions of sulfur dioxide (SO_2) and particulate matter from industrial-commercial-institutional steam generating units with heat input capacities of 29 MW (100 million Btu/hour) or larger (51 FR 22384; Subpart Db) under authority of Section 111 of the Clean Air Act. Public comments were requested on the proposal in the Federal Register. There were 99 commenters, composed mainly of industries, trade associations, and State regulatory agencies. Also commenting were U. S. Government agencies, an environmental group, and several nonaffiliated commenters. The comments that were submitted (see Docket A-83-27), along with responses to these comments, are summarized in this document. In those cases where EPA agreed with a comment, appropriate revisions to the final standards have been made.

1.1 SUMMARY OF CHANGES IN STANDARD

In most cases, the final standards require a 90 percent reduction in SO_2 emissions from coal- and oil-fired steam generating units. Maximum emissions are limited to 520 ng/J (1.2 lb/million Btu) for coal and 340 ng/J (0.8 lb/million Btu) for oil. These requirements are the same as those contained in the proposed standards. For steam generating units operating at an annual capacity utilization factor of less than 30 percent for coal and oil (or a mixture of coal and oil), no percentage reduction is required, but emission limits of 520 ng/J (1.2 lb/million Btu) for coal and 130 ng/J (0.3 lb/million Btu) for oil must be met. This is a new provision not included in the proposed standards. An exemption from the percentage reduction requirement has also been added for steam generating units located in noncontinental areas and firing very low sulfur oil [(130 ng/J (0.3 lb/million Btu))]. In addition, fluidized bed combustion steam generating units firing coal refuse are allowed to achieve 80 percent reduction in SO_2

emissions, subject to the same emission rate limit as for other coal-fired units. The requirements for emerging SO₂ control technologies; particulate matter emissions from oil-fired steam generating units; and monitoring, recordkeeping, and reporting requirements remain the same as those proposed.

1.2 SUMMARY OF IMPACTS OF PROMULGATED ACTION

1.2.1 Alternatives to Promulgated Action

Regulatory alternatives are discussed in Chapter 8 of "Summary of Regulatory Analysis for New Source Performance Standards: Industrial-Commercial-Institutional Steam Generating Units of Greater than 100 Million Btu/hr Heat Input" (EPA-450/3-86-005), referred to as the Summary of Regulatory Analysis.

1.2.2 Impacts of Promulgated Action

The proposed impacts associated with the final standards are summarized in Tables 1 and 2. Table 1 summarizes national impacts and Table 2 summarizes impacts on typical steam generating units.

Projected national impacts associated with the standards can vary considerably depending on the approach used to estimate these impacts. The approach used by the Agency starts with estimates of the growth in national energy consumption projected by the Department of Energy. These projections are used to estimate energy consumption in new industrial-commercial-institutional steam generating units. These energy consumption estimates, along with projections of future fuel prices, serve as inputs to a computer model known as the "Industrial Fuel Choice Analysis Model" (i.e., IFCAM).

With these input assumptions, IFCAM projects a population of new steam generating units distributed by geographic area, unit size, and operating level based on historical patterns. For each projected new steam generating unit, the total cost associated with each type of fuel that could be fired, including the costs to comply with standards limiting SO₂ emissions is calculated and the lowest cost alternative selected for compliance. The

TABLE 1. NATIONAL IMPACTS

	<u>IFCAM</u>	<u>Sales Data</u>
AIR EMISSION REDUCTIONS		
Sulfur Dioxide, thousand tons/yr	130 - 360	140
Particulate Matter, thousand tons/yr	9 - 24	3
LIQUID AND SOLID WASTES GENERATED		
Liquid Wastes, million ft ³ /yr	neg.	53
Solid Wastes, thousand tons/yr	neg.	270
ENERGY IMPACTS		
Increase in Natural Gas Use, trillion Btu/yr	110 - 310	-
COST IMPACTS		
Total Annualized Costs, million \$/yr	5 - 50	120
Average Cost Effectiveness, \$/ton	40 - 130	890
Incremental Cost Effectiveness, \$/ton	0	1,400

TABLE 2. TYPICAL STEAM GENERATING UNIT IMPACTS^a

	<u>Small^a</u>	<u>Large^b</u>
AIR EMISSION REDUCTIONS		
Sulfur Dioxide, tons/yr	1,200	780
Particulate Matter, tons/yr	54	0
LIQUID AND SOLID WASTE GENERATED		
Liquid Wastes, million ft ³ /yr	1.3	-
Solid Wastes, thousand tons/yr	-	2.7
COST IMPACTS		
Total Annualized Cost, thousand \$/yr	860	920
Average Cost Effectiveness, \$/ton	750	1,200
Incremental Cost Effectiveness, \$/ton	1,900	1,200

^aBased on a 150 MM Btu/hr oil-fired steam generating unit firing a low sulfur oil, operating at 55 percent annual capacity factor, and using a sodium FGD system to reduce SO₂ emissions, compared to a unit subject to SO₂ emission limits under a typical State Implementation Plan.

^bBased on a 400 MM Btu/hr coal-fired steam generating unit firing a medium sulfur coal, operating at 60 percent capacity factor, and using a lime spray drying FGD system to reduce SO₂ emissions, compared to a unit subject to Subpart D.

results are then aggregated to yield estimates of national impacts associated with standards limiting SO₂ emissions.

Using this approach, "fuel switching" from coal or oil to natural gas can occur in response to standards limiting SO₂ emissions. For example, in the absence of SO₂ standards, it may be less expensive to fire coal or oil than natural gas. With SO₂ standards, however, it may be less expensive to fire natural gas than to fire coal or oil. When fuel switching occurs, it results in lower costs and greater SO₂ emission reductions.

The type of fuel projected by IFCAM to be fired in each new steam generating unit as well as the likelihood of fuel switching occurring in response to standards, depends primarily on relative fuel prices. Given the uncertainty in projected fuel prices, a number of different fuel price scenarios were examined. The range of national impacts associated with those projections of fuel prices which are currently considered "most likely" is shown under the "IFCAM" column in Table 1.

Impacts of the final standards on typical steam generating units are summarized in Table 2. These impacts ignore the possibility of fuel switching and assume that a new steam generating unit which would fire coal or oil in the absence of standards will continue to fire coal or oil, regardless of the costs involved. The actual cost impacts would be lower and emission reductions higher if fuel switching had been assumed to occur.

A number of commenters stated that the approach used by the Agency to estimate national impacts (i.e., IFCAM) probably underestimated the costs and overestimated the emission reductions associated with the standards. Commenters suggested that both the amount of fuel switching projected to occur as well as the number of new steam generating units projected to be built were excessive. To respond to these concerns, an approach based on historical data was also used to estimate national impacts (shown under the "SALES DATA" column in Table 1).

This alternate approach is similar to that used to estimate the impacts on typical steam generating units. It uses annual steam generating unit sales statistics gathered by the American Boiler Manufacturing Association (ABMA) for the past five years to project a population of new industrial-

commercial-institutional steam generating units expected to be built in the next 5 years. The costs and emission reductions associated with the standards are estimated for each new coal- or oil-fired steam generating unit and no fuel switch is assumed to occur. The results are then aggregated to yield an alternative estimate of national impacts.

As shown in Tables 1 and 2, the final standards would result in significant reductions in SO_2 emissions from new industrial-commercial-institutional steam generating units on both a national and an individual basis. Tables 1 and 2 show the standards could, however, result in some increase in liquid and solid waste. The amount of liquid and solid waste generated depends on the amount of fuel switching that occurs. Where steam generating units fuel switch from firing coal or oil to firing natural gas, the SO_2 standards would not result in any waste generation and the standards could, in fact, result in a net decrease in liquid or solid wastes. Where fuel switching does not occur, the liquid or solid waste increase would depend on the type of FGD system installed to control SO_2 emissions. Some systems generate only liquid wastes, others generate only solid wastes.

Impacts on energy consumption associated with the final standards also depend on the extent to which fuel switching occurs. At most, the standards would result in less than a 5 percent increase in the amount of natural gas consumed by industrial sources. Much of this increased natural gas consumption, however, would be "balanced off" by a corresponding decrease in oil consumption.

The national average cost effectiveness of the standards, based on IFCAM, is projected to be in the range of \$40 to \$130/ton SO_2 removed. Using the alternative "SALES DATA" approach outlined above, the average cost effectiveness is projected to be \$890/ton. The national incremental cost effectiveness of the final standards over standards based on the use of low sulfur fuels is projected to be negligible if fuel switching is assumed to occur and up to \$1,400/ton if no fuel switching is assumed to occur.

Industry specific economic impacts were assessed for six industries which were considered likely to experience the most severe impacts. For

these industries, product prices were projected to increase by less than 0.01 to 1.5 percent in 1990, assuming "full cost pass-through" of all increased costs associated with standards requiring a percent reduction in SO₂ emissions. Assuming "full cost absorption," return on assets was projected to decrease by 0.03 to 2.8 percentage points.

1.2.3 Other Considerations

1.2.3.1 Irreversible and Irretrievable Commitment of Resources. Other than the fuels required for power generation and the materials required for the construction of the control systems, there is no apparent irreversible or irretrievable commitment of resources associated with this regulation.

1.2.3.2 Environmental and Energy Impacts of Delayed Standards. The results of delay in the standards are that new industrial-commercial-institutional steam generating units would be built that may not meet the emission limitations established by these standards. This would delay the ambient air quality and other environmental benefits associated with this NSPS.

1.2.3.3 Urban and Community Impacts. Neither plant closures nor impacts on small businesses are forecast. No significant adverse impacts on urban areas or local communities are anticipated as the result of the promulgation of these standards.

2.0 SUMMARY OF PUBLIC COMMENTS

A total of 99 letters commenting on the proposed standards were received. Comments were provided by industry representatives, governmental entities, and environmental groups. These comments have been recorded and placed in the docket for this rulemaking (Docket A-83-27, Category IV). Table 2-1 presents a listing of all persons submitting written comments, their affiliation and address, and the recorded Docket Item Number assigned to each comment letter.

In addition, 19 industry representatives presented oral comments on the proposed standards at a public hearing held on September 4, 1986. A verbatim transcript of the comments at the public hearing has been prepared and placed in Docket A-83-27, Category IV. Table 2-2 presents a listing of all persons presenting comments at the public hearing, their affiliation and address, and the recorded Docket Item Number assigned to the public hearing transcript.

The comments summarized in this chapter have been organized into the following categories:

- 2.1 Need for the Standard
- 2.2 Applicability
- 2.3 Basis of the Standard
- 2.4 Standard for SO₂
- 2.5 Standard for Particulate Matter
- 2.6 National Impacts
- 2.7 Cost of the Standard
- 2.8 Performance/Reliability of Demonstrated Technologies
- 2.9 Industry-specific Economic Impacts
- 2.10 Secondary Environmental Impacts
- 2.11 Regulatory Impact Analysis
- 2.12 Mixed Fuel-fired Steam Generating Units
- 2.13 Standard for Cogeneration Units
- 2.14 Standard for Emerging Technologies
- 2.15 Monitoring, Recordkeeping, and Reporting Requirements
- 2.16 Miscellaneous Comments

TABLE 2-1. LIST OF COMMENTERS ON THE PROPOSED STANDARDS FOR
SULFUR DIOXIDE EMISSIONS FROM INDUSTRIAL-COMMERCIAL-INSTITUTIONAL
STEAM GENERATING UNITS

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James K. Hambright Director, Bureau of Air Quality Control Pennsylvania State Air Pollution Control Agency 200 N. Third Street P. O. Box 2063 Harrisburg, PA 17120	D-1
Bruce Blanchard Director, Environmental Project Review U.S. Department of the Interior Office of the Secretary Washington, DC 20240	D-2
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D-20

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D-21

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R. Thorne, Director Corporate Office of Environmental Affairs Union Camp Corporation P. O. Box 1391 Savannah, GA 31402	D-84
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Sidney G. Nelson President Sanitech Inc. 1935 East Aurora Road Twinsburg, OH 44087	D-90
Jurgen H. Kleinau Marketing Manager Keeler Dorr-Oliver P. O. Box 548 Williamsport, PA 17703-0548	D-91

<u>Commenter</u>	<u>Docket Reference</u>
Michael Musheno Senior Program Manager Combustion Engineering, Inc. 800 Eastowne Drive Suite 200 Chapel Hill, NC 27514	D-92
Peter Rozelle The Pennsylvania State University Combustion Laboratory 405 Academic Activities Building University Park, PA 16802	D-93
Jan B. Vlcek James M. Bushee Sutherland, Asbill & Brennan 1666 K Street, N.W. Washington, DC 20006-2803 (for the Council of Industrial Boiler Owners)	D-94
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Douglas A. Riggs General Counsel U.S. Department of Commerce Washington, DC 20230	D-96
Peter C. Freudenthal Director, Air and Land Use Consolidated Edison Company of New York, Inc. 4 Irving Place New York, NY 10003	D-97
Bruce Blanchard Director, Environmental Project Review U.S. Department of the Interior Office of the Secretary Washington, DC 20240	D-98
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TABLE 2-2. LIST OF PUBLIC HEARING SPEAKERS ON THE PROPOSED STANDARDS
FOR SULFUR DIOXIDE EMISSIONS FROM INDUSTRIAL-COMMERCIAL-INSTITUTIONAL
STEAM GENERATING UNITS

<u>Speaker</u>	<u>Docket Reference</u>
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Peter C. Freudenthal Consolidated Edison Company of New York 4 Irving Place New York, NY 10003	F-1.4
David Pattee International Paper Company New York, NY	F-1.4a
Francis A. Ferraro Babcock and Wilcox Company 20 S. Van Buren Barberton, OH 44203	F-1.4b
Joseph W. Mullan National Coal Association Washington, DC 20036	F-1.4c
Edward Schwartz Peoples Natural Gas of Pittsburgh Pittsburgh, PA for American Gas Association	F-1.5

<u>Speaker</u>	<u>Docket Reference</u>
William Axtman American Boiler Manufacturers Association 950 N. Glebe Rd., Suite 160 Arlington, VA 22203	F-1.6
John Cuthbertson James River Corporation Richmond, VA for American Paper Institute/National Forest Products Association	F-1.7
Jerry L. Lombardo Island Creek Coal Company Lexington, KY for National Coal Association	F-1.8
Harry L. Storey Alliance for Clean Energy 555 17th Street Denver, CO 80202	F-1.9
John Stauffacher The Dow Chemical Co. B101 Bldg. Freeport, TX	F-1.10
Jeffrey Smith Industrial Gas Cleaning Institute 1707 L Street, N.W. Suite 570 Washington, DC 20036	F-1.11
William B. Marx Council of Industrial Boiler Owners 5817 Burke Centre Parkway Burke, VA 22015	F-1.12
Jan B. Vlcek Sutherland, Asbill & Brennan 1666 K Street, N.W. Washington, DC 20006 for Council of Industrial Boiler Owners	F-1.13
David Pattee International Paper Company New York, NY for Council of Industrial Boiler Owners	F-1.14

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Reference

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F-1.19

2.1 NEED FOR THE STANDARD

1. Comment: Many commenters (IV-D-6, IV-D-7, IV-D-10, IV-D-20, IV-D-26, IV-D-27, IV-D-28, IV-D-35, IV-D-36, IV-D-38, IV-D-40, IV-D-50, IV-D-51, IV-D-52, IV-D-54, IV-D-58, IV-D-62, IV-D-66, IV-D-72, IV-D-74, IV-D-78, IV-D-81, IV-D-84, IV-D-85, IV-D-88, IV-F-1.12, IV-F-1.19) said the standard was not necessary because total emissions from new industrial-commercial-institutional steam generating units will be insignificant, amounting to less than 1.5 percent of total U.S. SO₂ emissions. In addition, the commenters said, industrial-commercial-institutional steam generating unit SO₂ emissions have declined and will continue to decline due to energy conservation, reduction in heavy industrial capacity, existing State and local emission standards, and because most new steam generating units are installed to replace older units.

Another commenter (IV-F-1.14) felt that the effectiveness of Prevention of Significant Deterioration (PSD) regulations in limiting new steam generating unit emissions should be taken into account in developing NSPS. This commenter stated that the PSD review process alone, independent of any NSPS, would be sufficient to limit substantially SO₂ emissions from new installations. Other commenters (IV-D-51, IV-D-88) said that given the small amounts of oil combusted in industrial-commercial-institutional steam generating units, they do not constitute a significant source of SO₂ emissions. The commenters felt that it would require a large amount of money to remove just a small amount of air pollution and, therefore, that the standards were not justified.

Response: On August 21, 1979, a priority list for development of additional NSPS was published in accordance with Sections 111(b)(A) and 111(f)(1) of the Clean Air Act (44 FR 49222). This list identified 59 major stationary source categories that were not covered by NSPS, but that were judged to be "significant contributors," i.e., to contribute significantly to air pollution that could reasonably be expected to endanger public health or welfare. Fossil fuel-fired industrial steam generating units ranked eleventh on this priority list of sources for which NSPS would be established in the future.

Of the 10 sources ranked above fossil fuel-fired industrial steam generating units on the priority list, nine were major sources of volatile organic compound (VOC) emissions. Because there are many areas that have not attained the national ambient air quality standard for ozone, major sources of VOC emissions were accorded a very high priority. Of the remaining source categories, fossil fuel-fired industrial steam generating units were the highest ranked source of particulate matter and SO₂ emissions, and the second highest ranked source of NO_x emissions. The industrial-commercial-institutional source category is a significant contributor and, therefore, an appropriate source category for regulation. In addition, individual industrial-commercial-institutional steam generating units (both oil- and coal-fired) frequently emit or have the potential to emit more than 91 Mg/year (100 tons/year) of sulfur dioxide. Such sources are considered "major sources" under the Clean Air Act. Further, Section 111 does not require that NSPS be set for only those sources within a listed category which are themselves significant contributors. Instead, it directs that NSPS be set for all sources within a listed category unless the impacts of such NSPS would be unreasonable.

These standards are designed to achieve reductions in SO₂ emissions from all new, modified, and reconstructed industrial-commercial-institutional steam generating units. The purpose of an NSPS is to provide a uniform national standard that requires the best demonstrated level of control, considering cost, energy, and environmental factors. Other programs that include local and/or site-specific requirements, such as PSD and NSR, may be more stringent than the NSPS.

2. Comment: One commenter (IV-D-4) suggested that instead of regulating the steam generating unit users, who are many, only the fuel producers, who are few in comparison, should be regulated. That way, the commenter said, the sulfur content of the fuel sold could be regulated, eliminating the need for continuous stack monitoring or emission control devices and reducing the paperwork burden on both industry and government.

Response: Section 111 of the Clean Air Act authorizes regulation of new "sources" of air pollution only. It does not authorize establishment of national standards for the sulfur content of fuels. The costs and administrative resources required to implement the final standards for both government and industry are considered reasonable, even though the number of owners and operators affected under the standards is greater than if fuel producers were regulated.

2.2 APPLICABILITY

1. Comment: Several commenters said that the standards should be limited to steam generating units with heat input capacities greater than 73 MW (250 million Btu/hour). One (IV-D-52) stated that the 1979 decision to regulate utility units larger than

73 MW (250 million Btu/hour) fulfilled the Section 111 mandate to regulate this source category, and that emissions from units in the smaller size category represent only a very small portion of the total emissions from the source category. Other commenters (IV-D-14, IV-D-40, IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-78, IV-D-84, IV-F-1.7, IV-F-1.8) agreed, saying that these smaller steam generating units will account for less than 1 percent of total national SO₂ emissions. In addition, the commenters said, emissions from new small steam generating units are already controlled by State Implementation Plan (SIP), PSD, and other State and local regulations. Finally, the commenters claimed that the sophisticated operation and maintenance required to operate post-combustion SO₂ control systems will simply be unavailable or, at best, inadequate in most small industrial operations.

Response: Section 111(a) of the Act requires that standards of performance reflecting the degree of emission reduction and the percentage reduction achievable through application of best demonstrated technology be established for categories of fossil fuel-fired sources which are "significant contributors" to air pollution. The language of Section 111(a) of the Act does not limit application of NSPS only to electric utility units or to units above a certain size. Section 111 requires the establishment of NSPS that reflect "the best technological system of continuous emission reduction which... has been adequately demonstrated" for sources in a listed category. It does not require that NSPS be set within a listed category only for classes of sources which are themselves significant contributors. As discussed above, industrial-commercial-institutional steam generating units are considered to be significant contributors of air pollution because of their particulate matter, NO_x, and SO₂ emissions.

Emissions from steam generating units with heat input capacities less than 73 MW (250 million Btu/hour) are currently not controlled with any degree of consistency. While some facilities are well controlled by SIP, PSD, and other programs, others are subject to much less stringent standards, or no standards at all. Therefore, this NSPS will provide a uniform level of control with which all new, modified, or reconstructed facilities must comply.

With respect to operation and maintenance of control equipment, the requirements of these standards are considered reasonable. The additional costs associated with this operation and maintenance were included in assessing the impacts of the standards, as discussed in the "SO₂ Cost Report." Proper operation and maintenance may, however, require an increased management commitment on the part of some owners/operators. In the event that owners/operators of smaller steam generating units would prefer not to spend the additional resources necessary for proper operation and maintenance of flue gas desulfurization or fluidized bed combustion systems, alternatives, such as the use of natural gas, are available.

2. Comment: One commenter (IV-D-37) said that the standards should be revised to include those units with heat input capacities of 22 MW (75 million Btu/hour) or greater. The commenter claimed that many plants construct multiple smaller units instead of one larger unit, and said that these sources should be regulated to dissuade facilities from constructing smaller units specifically for the purpose of avoiding NSPS requirements.

Response: These standards apply to individual steam generating units with heat input capacities greater than 29 MW (100 million Btu/hour) primarily because the steam generating unit population above that size is characterized predominantly by industrial units. Below 29 MW (100 million Btu/hour) heat input capacity, the steam generating unit population tends to be more of a mixture of industrial, commercial, and institutional applications. For this reason, it was decided to develop standards first for steam generating units above 29 MW (100 million Btu/hour) heat input capacity in size, followed by standards for units below that size. Standards for industrial-commercial-institutional units with heat input capacities of 29 MW (100 million Btu/hour) or less are currently being developed with final promulgation scheduled for 1990. Once standards for these smaller boilers are promulgated, construction of units smaller than 29 MW (100 million Btu/hour) for the purpose of evading regulation will not be possible.

3. Comment: Several commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-F-1.12) said that the standards should be limited to "fossil fuel-fired boilers," i.e., steam generating units firing more than 50 percent conventional fossil fuel during a year. According to these commenters, mixed fuel-fired steam generating units have advantages such as lower SO₂ emissions, conservation of fossil fuels, and disposal of waste materials that should not be discouraged.

Response: Mixed fuel-fired steam generating units can be significant sources of SO₂ emissions even when less than 50 percent fossil fuel is fired. Because mixed fuel-fired units tend to be large, the fossil fuel heat input and, thus, the emissions of such units can exceed that of smaller units

that fire 100 percent fossil fuel. The control technologies for reducing SO₂ emissions are as effective on steam generating units firing mixtures of fossil fuel with nonfossil fuel as they are on units firing fossil fuel alone. Also, the cost and economic impacts of the standards on mixed fuel-fired steam generating units firing mixtures of fossil and nonfossil fuels were assessed (see "Impact of New Fuel Prices on the Costs and Cost Effectiveness of SO₂ Emission Control of Mixed Fuel-Fired Steam Generating Units," and the impacts of the final standards on such units are considered reasonable.

As evidenced in the proposed standards, however, the analysis identified one situation under which the impacts of standards requiring a percent reduction in emissions could be unreasonable for mixed fuel-fired steam generating units. If the amount of coal or oil fired in a mixed fuel-fired generating unit is less than 30 percent of its rated heat input capacity on an annual basis, the costs associated with achieving a percent reduction in SO₂ emissions are considered unreasonable. Consequently, such mixed fuel-fired steam generating units are exempt from the percent reduction requirement in the final standards. These units, however, will be required to comply with an emission limit for SO₂.

4. Comment: One commenter (IV-D-95) stated that municipal solid waste combustion facilities with over 29 MW (100 million Btu/hour) heat input capacity should be classified as affected facilities under the standards. The commenter noted that the State of New Jersey requires at least an 80 percent reduction in SO₂ from these facilities when potential emissions exceed 50 ppmv.

Response: Although use of municipal solid waste, wood, and natural gas is subject to regulation under the industrial-commercial-institutional steam generating unit source category, the sulfur content of the fuels, and thus their SO₂ emission potential, is generally low. As a result, the costs for installation of FGD technology for the purpose of SO₂ control would be high and resulting cost-effectiveness levels unreasonable. Therefore, these standards are limited to steam generating units firing coal and oil alone or in combination with other fuels. If only solid waste is combusted, the standards would not apply. However, if a facility combusts solid waste in combination with coal or oil, it would be subject to the standards. It should also be noted that the particulate matter standards promulgated for this source category on November 25, 1986 (51 FR 42768) would apply to units firing solid waste, either alone or in combination with other fuels.

As a separate regulatory action, the Agency has also assessed the unique environmental problems presented by the combustion of municipal solid waste and, as a result, concluded that additional regulations specific to the combustion of municipal solid waste are appropriate (52 FR 25399). Under this separate action, the Agency has provided operational guidance to State and local authorities for use in reviewing prevention of significant deterioration (PSD) permits under 40 CFR 51.24. Additional regulations are currently under development.

5. Comment: One commenter (IV-D-28) suggested that a regulatory clarification be added to state that any change to an existing steam generating unit, originally designed to accommodate gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) does not

bring that unit under the applicability of the subpart. Such a provision, the commenter said, was included in the 1979 Utility NSPS at 40 CFR 60.40a(d), and adoption of it in this standard could significantly mitigate potential adverse energy impacts associated with the standards. The commenter also suggested that the preamble to the final standard also contain a discussion that alteration of these steam generating units to fire, for example, coal/oil/water mixtures, coal/oil mixtures, shale oil, or liquified or gasified coal, would not result in the facility becoming subject to the standard under the modification/reconstruction provisions.

Response: Fuel conversions are exempt from the modification provision under two circumstances: (1) where the facility was designed to accommodate the alternative fuel prior to the date of the applicable NSPS subpart [40 CFR 60.14(e)(4)]; or (2) where the facility is required to convert to coal pursuant to an order issued under Title III of the Powerplant and Industrial Fuel Use Act of 1978 (42 U.S.C. 8301 et seq.), as amended [40 CFR 60.14(e)(4) and Section 111(a)(8) of the Clean Air Act]. In other instances where the facility is altered to burn coal or waste fuels, the facility may be subject to the standards if it qualifies as a modified or reconstructed unit as defined in 40 CFR 60.14 or 60.15 of the General Provisions.

The modification clause in the General Provisions (60.14) defines a modification as "any physical or operational change to an existing facility which results in an increase in the emission rate...." Therefore, the modification provision can be avoided by ensuring that the emission rate (ng/J or lb/million Btu) does not increase as a result of

the changes made (generally by the use of fuel with a sulfur content equivalent to or lower than the fuel used originally). In addition, the reconstruction provisions apply only when changes made to the facility exceed 50 percent of the fixed capital costs associated with constructing a new facility. Few, if any, changes that could be made to a steam generating unit would be expected to exceed this limit. Therefore, few reconstructed units are expected to be affected under the standards.

6. Comment: One commenter (IV-D-55) stated that the proposed standards should be amended to allow low sulfur content fuels rather than FGD for modified and reconstructed steam generating units. The commenter contended that the cost and feasibility problems associated with retrofitting an existing unit to accommodate an FGD system would be substantial.

Response: As discussed above, the General Provisions of 40 CFR Part 60 define modified and reconstructed facilities. A modification, as defined in 60.14 of the General Provisions, includes certain physical or operational changes to an existing facility which result in an increase in the emission rate. As long as emissions can be maintained at or below the level measured before the change occurred, the change would not qualify as a modification. A reconstructed facility, under 40 CFR 60.15, is one in which replacement of components constitutes at least 50 percent of the fixed capital cost of a comparable new facility and which can technologically and economically meet the standards. In the case of reconstructed facilities, a determination is made on a case-by-case basis from an examination of the technical and economic feasibility of complying with the standards.

Thus, the reconstruction provision already provides for exemptions when costs or technical feasibility create problems, and the modification provisions can be avoided by ensuring that there is no increase in the emission rate. In addition, no general types of modifications or reconstructions of industrial-commercial-institutional steam generating units have been identified where compliance with the standards would be unreasonable. Therefore, no provisions have been included for an alternative compliance option for modified or reconstructed units.

7. Comment: A number of commenters felt that steam generating units operating at low capacity factors should be exempted from the SO₂ standards. Several (IV-D-55, IV-D-56, IV-D-57, IV-D-72, IV-D-74, IV-D-78, IV-D-79, IV-D-80, IV-D-85) said the percent reduction requirement of the proposed standards should not be applicable to steam generating units operating at low capacity utilization rates. One (IV-D-49) suggested that if a steam generating unit operates at an average fuel utilization rate (for fuels other than natural gas) of 30 percent or less during a 30-day period, it should be exempt from compliance with the standard. The commenter said such a capacity factor exemption could be related to the percent sulfur in the fuel used. Others (IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-D-76) said the rationale for not allowing an exemption from the percent reduction requirement for low capacity (less than 30 percent) fossil fuel-fired steam generating units while allowing it for mixed fuel-fired units is invalid, since the same cost effectiveness numbers are used for both. The commenters stated that EPA should not assume that mixed fuel fired units would behave differently than low capacity factor units. Several commenters (IV-D-21, IV-D-34, IV-D-41, IV-D-56, IV-D-57,

IV-D-85) felt that electric utility auxiliary steam generating units which operate at low capacity factors (e.g., 10 or 20 percent) should not be subject to the standards.

One commenter (IV-D-12) said special exemptions from compliance with the standards should be allowed for units which operate less than 6 months of the year. If a total exemption is not possible, the commenter suggested an arrangement should be made so that the average air emission effects over the entire year can be considered when determining the applicability of the proposed standards. Another commenter (IV-D-64), however, stated that there should be no exemptions from the percent reduction requirement given on the basis of size or capacity utilization rates. The commenter said the difference in emission reductions achieved by FGD over low sulfur fuel is significant for all size classes of steam generating units, and the costs of compliance are only marginally greater for small or low capacity units.

Response: As noted by the commenters, there are many types of industrial-commercial-institutional steam generating units that operate with low annual capacity factors (capacity utilization rates). These include auxiliary steam generating units located at electric utility power plants that are used to start up main steam generating units, units operated infrequently as "backup" steam capacity at industrial plants, mixed fuel-fired steam generating units burning small amounts of coal or oil, and nonfossil fuel-fired steam generating units that use oil or coal as a backup fuel during periods when nonfossil fuel is unavailable.

Review and reconsideration of the initial analysis, recent steam generating unit sales data, and recent operations data from new steam generating units leads to the conclusion that some plants will install coal- or oil-fired steam generating units even where natural gas is the fuel of economic choice and despite promulgation of standards requiring a percent reduction in emissions from coal- and oil-fired steam generating units. For most applications, the cost of applying percent reduction requirements to coal- and oil-fired steam generating units will be reasonable.

However, as in the case of mixed fuel-fired units, low capacity factor steam generating units which obtain less than 30 percent of their rated annual heat input capacity from the combustion of coal or oil could well experience unreasonable impacts. The final regulation, therefore, does not require a percent reduction in SO_2 emissions from steam generating units operated at low annual capacity utilization factors, provided a Federally enforceable permit condition limits the annual capacity utilization factor for coal or oil to less than 0.3 (i.e., 30 percent of the rated capacity of the steam generating unit). If a decision is subsequently made to operate with a coal and oil annual capacity factor greater than 30 percent, compliance with the percent reduction requirement would be necessary.

These "low capacity factor" steam generating units would, however, be required to meet certain emission limits. Emissions of SO_2 from steam generating units operating at annual capacity factors of 30 percent or less would be limited to 516 ng/J (1.2 lb/million Btu) heat input if coal is fired and 129 ng/J (0.3 lb/million Btu) if oil is fired.

These emission limits were selected based on the availability of low sulfur coal and oil throughout the U.S. Continuous emission monitoring, continuous compliance provisions, and quarterly reporting are required for all units, including these "low capacity factor" units.

8. Comment: Several commenters (IV-D-11, IV-D-20, IV-D-26, IV-D-30, IV-D-38, IV-D-42, IV-D-45, IV-D-49, IV-D-50, IV-D-53, IV-D-58, IV-D-62, IV-D-65, IV-D-66, IV-D-74, IV-D-76, IV-D-84, IV-F-1.7) said a percentage reduction requirement should not be issued for steam generating units with low capacity utilization rates for oil, such as those using oil for backup or pilot fuel purposes. They felt that, given the small amounts of oil combusted, these units do not constitute significant emission sources, and the high cost of achieving the reduction would be out of proportion to the amount of pollution removed. One commenter (IV-D-92) requested clarification on this point, asking whether the SO₂ percent reduction requirement applies to steam generating units that use oil only for startup and then burn a nonfossil fuel such as municipal solid waste. The commenter also asked whether the SO₂ reductions would apply if gas is used as the startup fuel instead of oil.

Response: As discussed above, an exemption from the percent reduction requirement has been granted for steam generating units operating at low annual capacity utilization factors, provided a Federally enforceable permit condition limits the annual capacity utilization factor for coal or oil to less than 30 percent of the rated capacity of the steam generating unit. Therefore, the types of steam generating units mentioned by the commenters would not be required to achieve a percent reduction in SO₂ emissions.

9. Comment: Several commenters (IV-D-16, IV-D-18, IV-D-19, IV-D-24, IV-D-25, IV-D-43, IV-D-59, IV-D-66, IV-D-67, IV-D-69, IV-D-71, IV-D-85, IV-D-89) said sources burning anthracite coal or anthracite mining waste (culm) should be exempted from the standards. They said the 1979 Electric Utility NSPS granted special provisions for anthracite, and felt that the reasons for granting those provisions are equally applicable to industrial-commercial-institutional steam generating units. Several of these commenters (IV-D-18, IV-D-19, IV-D-24, IV-D-25, IV-D-43, IV-D-67) said that the secondary environmental benefits associated with burning low sulfur anthracite coal have been overlooked. In particular, they noted, the use of anthracite mining waste (culm) in steam generating units is of great benefit to the local environment in the anthracite mining areas of Pennsylvania and should be encouraged, not discouraged. To date, the commenters said, the only technically and economically feasible means of disposing of this waste is through combustion in a fluidized bed steam generating unit.

Response: The exemption from the percent reduction requirement granted for anthracite in Subpart Da was provided to encourage reclamation of anthracite mines, resulting in environmental benefits such as improvement of mine drainage acid-water conditions, elimination of old mining scars on the topography, and eradication of dangerous fires in deep mines and culm banks. At the time of promulgation of Subpart Da (June 1979), reclamation of areas that had been despoiled by mining was a high priority, as evidenced by the passage of the Federal Surface Mining Control and Reclamation Act. The exemption from the percent reduction requirement provided under Subpart Da for anthracite created a market for this fuel in the utility sector, and the environmental benefits

associated with this large-scale utility reclamation were judged to outweigh any ambient air quality impacts of burning anthracite without a post-combustion SO₂ control system.

The small projected overall coal demand in the industrial-commercial-institutional steam generating unit market, combined with the predominant use of locally available coals, would generally result in anthracite being used as a local fuel only, even if an exemption from the percent reduction requirement was granted for anthracite. The small quantities of coal demanded by the industrial sector in northeastern Pennsylvania and other areas of localized anthracite deposits would not result in the large-scale utility-type reclamation of abandoned mines that might have resulted from the Subpart Da exemption. Therefore, no special provisions for anthracite have been included in the final standards.

A different situation exists, however, with the firing of anthracite mining waste and other coal mining and washing wastes (collectively referred to as coal refuse). These waste piles are not only unsightly, but they are responsible for acid drainage problems and can also lead to fires from spontaneous combustion. Therefore, it is important to encourage the use of these wastes as fuels in steam generating units (specifically fluidized bed combustion steam generating units) to eliminate a potential environmental hazard. Consequently, a less stringent percent reduction requirement of 80 percent has been provided for fluidized bed combustion steam generating units which fire coal refuse. This action balances the need to minimize air pollution from combustion of these wastes

against the environmental benefits resulting from eliminating waste fuel piles.

10. Comment: One commenter (IV-D-33) said the standard should include an exemption for noncontinental areas such as Hawaii, as was done in Subpart Da. The commenter asserted that these areas have unique environmental problems associated with disposal of solid and liquid wastes resulting from SO₂ control, as well as a lack of flexibility in fuel choice (i.e., natural gas is not available in Hawaii). According to the commenter, these special situations, plus additional operating costs such as shipping large quantities of alkaline chemical reagents, result in exorbitant compliance costs for sources in island areas.

Response: Facilities in noncontinental areas (Hawaii, the Virgin Islands, Guam, American Samoa, Puerto Rico, and the Northern Mariana Islands) constitute a subcategory subject to unique environmental and economic constraints in complying with this NSPS. Because of a lack of natural gas supplies, "fuel switching" to natural gas is not feasible.

In addition, the cost of importing FGD reagent and other materials to noncontinental areas would make the costs associated with achieving a percent reduction in emissions much higher in these areas than on the continental mainland.

In light of these unique considerations, an exemption from the percent reduction requirement has been provided for steam generating units located in noncontinental areas, regardless of the capacity factor of the unit. Such facilities are, however, required to meet the SO₂ emission limitations discussed above for units operating at low

capacity factors for coal or oil. These emission limits, as well as the fact that these facilities will be reviewed to ensure compliance with PSD limitations, will minimize the impact of these facilities on ambient air quality.

2.3 BASIS OF THE STANDARD

1. Comment: One commenter (IV-D-63) said that the standard should provide for the reasonable control of emissions from any fuel a source elects to use and, therefore, the standard should not directly or indirectly prohibit the use of coal or oil. The commenter added that, although the nominal control technique that forms the basis of the standard is the installation of a flue gas desulfurization (FGD) system, the actual control system proposed is the use of natural gas as a steam generating unit fuel, since the cost of installing and using an FGD system would represent an unreasonable burden on sources having units in the smaller size range covered by this standard.

Response: The standard does not prohibit the use of either coal or oil as a steam generating unit fuel, and their continued use is anticipated. The increased costs and economic impacts associated with operating an FGD or FBC system to control emissions from coal- or oil-fired steam generating units have been examined and are considered reasonable. It is also anticipated, however, that a number of new steam generating units that might have been designed to fire coal or oil will be designed and constructed to fire natural gas in response to these standards. The magnitude of this switch in fuels will vary depending on local fuel prices. The anticipated reductions in coal and oil use and the anticipated increases in natural gas use in industrial steam

generating units are also considered reasonable in light of the associated decreases in SO₂ emissions.

2. Comment: One commenter (IV-D-76) stated that the need for a percent reduction requirement should be explicitly examined in terms of emission reductions achieved and cost, energy and environmental impacts. The commenter suggested that an emission limit should be considered as the basis of the standard.

Response: In the development of this standard, a number of regulatory alternatives were considered and analyzed. Various requirements for a percent reduction in SO₂ emissions as well as standards limiting SO₂ emissions to a specific emission limit were among the alternatives examined. The analyses of these alternatives examined the cost, energy, and environmental impacts, as well as the overall economic impacts, of each alternative.

Under Section 111(a) of the Clean Air Act, NSPS for fossil fuel-fired stationary sources are required to include both an emission limit and a percentage reduction requirement, unless the imposition of a percentage reduction requirement would result in unreasonable cost, environmental, or energy impacts. Percent reduction requirements are considered reasonable for most subcategories of industrial-commercial-institutional steam generating units. There are exceptions, however, for which exemptions have been granted. For example, steam generating units firing coal or oil, or a mixture of coal and oil, at less than 30 percent of their rated capacity on an annual basis, units located in noncontinental areas, or units firing very low sulfur oil

are not required to achieve a percent reduction in SO₂ emissions, but need meet only certain emission limits.

3. Comment: A number of commenters questioned the legal basis for establishing a percent reduction requirement as the basis of the standard. Several (IV-D-26, IV-D-29, IV-D-30, IV-D-35, IV-D-38, IV-D-40, IV-D-46, IV-D-50, IV-D-53, IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-75, IV-D-81, IV-D-82, IV-D-84, IV-D-85, IV-F-1.1, IV-F-1.7, IV-F-1.10, IV-F-1.13) said the legislative history of the percent reduction provision indicates that it was intended by Congress to apply to utility steam generating units only, and not to industrial steam generating units. Several (IV-D-26, IV-D-30, IV-D-44, IV-D-50, IV-D-52, IV-D-53, IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-75, IV-D-78, IV-D-84, IV-F-1.7, IV-F-1.13) added that Section 111 gives the Agency the flexibility to forgo a percentage reduction where there is no demonstrated need for it, or where the costs are too high compared to the benefits, or where a percent reduction would create more problems than it solved. The commenters said that all these things are true of this proposal. Some (IV-D-26, IV-D-52, IV-D-56, IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-75, IV-D-81, IV-D-84) said the Agency itself relied on the "ambiguous legislative history" of the Clean Air Act Amendments after promulgation of the utility steam generating unit standards when it was concluded that there was no obligation to revise the existing large industrial steam generating unit NSPS to include a percent reduction requirement. The commenters referred to a brief filed by the Agency in Sierra Club v. Ruckelshaus in 1984. One commenter (IV-D-96) said the legislative history of Section 111 indicates that the percent reduction concept was introduced into the statute specifically to avoid fuel

switching away from coal. Thus, the commenter said, the 90 percent reduction requirement in the proposed standard defeats the primary purpose of this clause. Another (IV-D-64), however, stated that Section 111(a)(1)(A)(ii) of the Clean Air Act mandates the percent reduction approach and is clearly applicable to this standard.

Response: Section 111(a)(1) defines the term "standard of performance" as follows:

"(A) with respect to any air pollutant emitted from a category of fossil fuel fired stationary sources... a standard -

(i) establishing allowable emission limitations for such category of sources, and

(ii) requiring the achievement of a percentage reduction in the emissions from such category of sources from the emissions which would have resulted from the use of fuels which are not subject to treatment prior to combustion."

The percentage reduction requirement was enacted by the 1977 Amendments to the Act. The Conference report characterizes this requirement as applying to "fossil fuel-fired sources" generally, not limited to utility steam generating units [S. Rep. No. 564, 95th Cong., 1st Sess. 130 (1977)]. The House Report, where the percentage reduction requirement originated, similarly refers to "fuel-burning new stationary sources" generally [H. R. Rep. No. 294, 95th Cong., 1st Sess. 188 (1977); *id.* at 188-192]. The Conference Report's discussion of the percentage reduction requirement indicates that the Agency has the authority to include a percentage reduction requirement in an NSPS for fossil fuel-fired sources [H. R. Rep. No. 564, 95th Cong., 1st Sess. 130

(1977)]. None of the discussion in the committee reports or the Congressional Record indicated the percent reduction requirement was to be limited to only electric utility steam generating units.

Although the discussion of the percentage reduction requirement in the legislative history sometimes refers to particular types of fossil fuel-fired sources, it is not true that the only type referred to is a utility steam generating unit. The legislative history also refers to "boilers" generally and "industrial sources," [*id.* at 189] and "mines, processing plants, and factories," [*id.* at 191] [*Accord, Sierra Club v. Ruckelshaus*, Civil Action No. 84-0325 (D.D.C. Sept. 4, 1985), at 5].

The issue in Sierra Club was the scope of the nondiscretionary duties under Section 111(b)(6). The Agency did not express any view in that case about the application to industrial steam generating units of the percentage reduction requirement under Section 111(a)(1), but simply argued that Section 111(b)(6) did not impose a nondiscretionary duty to promulgate revised NSPS for industrial steam generating units. Similarly, the utility steam generating unit NSPS rulemaking cited in that brief did not analyze the applicability of the percentage reduction requirement to industrial steam generating units [44 FR 33580 (June 11, 1979); 43 FR 42154 (Sept. 19, 1978)].

The legislative history of the percent reduction standard does indicate that one of its purposes was to reduce economic incentives to use low sulfur coal rather than applying control technology on higher sulfur, but locally available fuels. However, there is no indication in the

legislative history of the percent reduction requirement that Congress sought to restrict the use of natural gas or other sulfur-free fuels.

Section 111 does provide the flexibility to forgo the percentage reduction requirement if the impacts associated with it would be "unreasonable." However, as discussed throughout this rulemaking, a thorough analysis of the economic, environmental, and energy impacts associated with the standard was conducted, and no unreasonable impacts were identified for the final standards. The preamble to the proposed NSPS explained in detail the legal, policy, and factual bases of the proposal, including an analysis of the extent to which the standard would discourage the burning of coal. Therefore, promulgation of the standard under Section 111 was carefully considered and is considered appropriate.

4. Comment: Several commenters (IV-D-8, IV-D-22, IV-D-44, IV-D-54, IV-D-60, IV-D-61, IV-D-83, IV-F-1.2, IV-F-1.4, IV-F-1.6, IV-F-1.9, IV-F-1.19) said only an emission limit, rather than a percent reduction requirement, should be established and sources should be allowed to achieve that limit by whatever means is appropriate for each source. They said that industry needs to have clearly understood nationwide regulations on emission rates while retaining freedom to choose the engineering method, fuel, and equipment to meet those emission rates. The commenters felt the percent reduction requirement preempts this freedom of choice. One commenter (IV-D-62) said the language of Section 111(b)(1)(B)(5), stating that the Administrator is not allowed to require any new or modified source to install a particular technological system, also means that the use of

low sulfur fuel as a method of compliance cannot be disallowed. The commenter added that while a demonstrated percent reduction may be used to establish an emission limit for new sources based on the dirtiest fuel commercially available, Section 111 does not authorize the inclusion of such a percentage reduction as a part of the standard of performance. According to the commenter, the percent reduction requirement of the Clean Air Act does not authorize the setting of a minimum efficiency level that control equipment must meet. Instead, the commenter said, it authorizes the Administrator to establish percent reduction needed via fuel cleaning, pollution control equipment, etc., for sources using the highest polluting fuel commercially available.

Response: The percent reduction requirement does not force a source to install any particular technological system of SO₂ emission reduction. It is simply a performance standard that is based on the performance capabilities of the "best demonstrated technology" (i.e., flue gas desulfurization or fluidized bed combustion). Sources are free to use any technological system that allows compliance with the standard.

The standard does not require that post-combustion control technology alone meet the percent reduction requirement. As such, pretreatment of fuels prior to combustion can be used to reduce the percent reduction required from the post-combustion control system.

5. Comment: One commenter (IV-D-96) stated that the Clean Air Act mandates that emissions be controlled by technological methods. The commenter said fuel switching is not a technological method of control and cannot be considered an "adequately demonstrated" technology.

Response: Section 111 requires NSPS to be set at the level which reflects the capabilities of the "best demonstrated technology," i.e., the most effective technology that does not impose unreasonable costs or other impacts [Essex Chemical Corp. v. Ruckelshaus, 486 F. 2d 427 (D.C. Cir. 1973)]. The best demonstrated technologies for coal- and oil-fired industrial-commercial-institutional steam generating units are flue gas desulfurization and fluidized bed combustion; therefore the NSPS has been established at the level reflecting the capabilities of these technologies. In so doing, the cost and other impacts were considered. As discussed elsewhere, those impacts are considered reasonable. Some fuel switching from oil or coal to natural gas will occur and is an alternative for owners or operators of affected facilities. However, this does not change the fact that the standards are based on use of flue gas desulfurization technology and fluidized bed combustion, and the impacts of requiring these technologies are reasonable even without fuel switching considerations. The legislative history shows that Congress intended that NSPS for coal- and oil-fired sources should reflect technological systems such as flue gas desulfurization and fluidized bed combustion [H. R. Rep. No. 294, 95th Cong., 1st Sess. 183-195 (1977)]. That intent is carried out by this NSPS.

2.4 STANDARD FOR SO₂

1. Comment: One commenter (IV-D-35) felt that coal cleaning should be considered as a compliance option under the standard. The commenter stated that the use of cleaned coal is an especially important emerging pollution control option, and cautioned that a standard based solely on the more expensive scrubbing technology ignores the potential for a more cost-effective coal cleaning approach.

Response: Coal cleaning is a demonstrated method of removing sulfur from coal. However, it is currently not capable of achieving the percentage sulfur removal that is achievable by the "best demonstrated technology," which is flue gas desulfurization or fluidized bed combustion. Therefore, the use of coal cleaning alone would not be sufficient to meet the promulgated standards. In addition, coal cleaning alone (which generally achieves only about 20 to 30 percent reductions in potential SO₂ emissions) was not intended by Congress to satisfy the provisions of Section 111 of the Clean Air Act and, therefore, cannot serve as the basis for an NSPS.

Coal cleaning was, however, considered as a means of producing low sulfur fuels, and the alternative of basing standards on the combustion of low sulfur fuel was given full and complete consideration. In addition, the definition of "potential SO₂ emission rate" (60.41b) is based on the emissions from the combustion of a fuel "in an uncleaned state," meaning that reductions in SO₂ emissions achieved through coal cleaning are creditable toward the percent reduction requirement.

2. Comment: Several commenters (IV-D-6, IV-D-28, IV-D-40, IV-D-50, IV-D-52) stated that because there are important differences between industrial and utility steam generating units, regulation of these two source categories should be based on these differences rather than treating industrial and utility units alike, which, according to the commenters, is what the proposed regulation does. The commenters specifically mentioned the following differences:

- Industrial steam generating units produce much less steam per hour than do utility steam generating units. They said a typical utility unit produces 3.5 million pounds of steam per hour, compared to only 0.1 million pounds per hour for a typical industrial unit.
- While utility units serve a single purpose - generating steam at a relatively steady rate to produce electricity, industrial units serve a variety of different purposes in various industries. Therefore, industrial steam generating unit design varies greatly depending on the fuels burned, the application of the steam produced, and the daily and seasonal load variations. According to the commenters, even at a single industrial operation the steam requirements can change drastically from day to day, hour to hour, and sometimes from minute to minute.
- Industrial units often burn a wide variety of fuels and process wastes available on-site, while utility units burn a relatively homogeneous coal.

The commenters said that all of these characteristics require a great deal of flexibility and reliability not required by utilities and need to be considered in setting a regulation.

Response: The various design and operational characteristics unique to industrial-commercial-institutional steam generating units were considered in developing the standards. It is true that industrial units are, in most cases, different from utility units. However, the analyses of performance, cost, and cost effectiveness of control technologies were performed on industrial size units with design and operation features typical of these units. The "model boiler" analysis was performed using steam generating units of 29, 44, and 117 MW (100, 150, and 400 million Btu/hour) heat input capacity rather than on larger size units. Assumptions such as frequent startup and shutdown, and variable steam demand resulting in load swings, were also considered when assessing performance of the SO₂ control technologies and factored into the cost algorithms. To account for the smaller lot size of the fuel purchases made by industrial operations, higher fuel costs than those attributed to utilities were also assumed. Differences in FGD malfunction assumptions were also taken into account in the use of natural gas as a backup fuel rather than maintenance of spare FGD module or steam generating unit shutdown, which is an option for electric utilities due to the ability to purchase electricity from the "grid" system. In addition, the analysis examined the use of package FGD systems, which are typical of industrial applications, rather than larger, field-erected FGD systems, which are typical of utility applications. Finally, separate analyses of mixed fuel-fired units were performed to account for industrial use of wood, solid waste, or other alternative fuels in addition to coal, oil, and natural gas. Thus, the major differences between industrial and utility steam generating units were considered and the requirements of the standards reflect these considerations.

3. Comment: Several commenters (IV-D-6, IV-D-7, IV-D-12, IV-D-28, IV-D-40, IV-D-48, IV-D-50, IV-D-52, IV-D-74, IV-D-83, IV-D-85) said a less stringent standard without a percent reduction requirement, or no standard, should be set for steam generating units with heat input capacities between 29 and 73 MW (100 and 250 million Btu/hour) because:
- they represent only 18 percent of the aggregate industrial-commercial-institutional steam generating unit capacity and less than 0.3 percent of total U.S. SO₂ emissions;
 - the SO₂ emissions generated by these units are insignificant to health and welfare considerations;
 - capital-related costs for SO₂ control are disproportionately higher due to a lack of economies of scale;
 - coal transportation costs are higher due to an inability to obtain volume shipping savings.

A number of commenters (IV-D-6, IV-D-26, IV-D-28, IV-D-30, IV-D-40, IV-D-46, IV-D-50, IV-D-52, IV-D-53, IV-D-72, IV-D-75, IV-F-1.16) also felt that even an emission limit of 516 ng/J (1.2 lb/million Btu) is not justified for steam generating units with heat input capacities less than 73 MW (250 million Btu/hour) on the basis of the volume of SO₂ emitted by this group and the disproportionate share of the costs they would bear. They contended that a higher standard, such as 688 or 1,033 ng/J (1.6 or 2.4 lb/million Btu), could be applied to these units with no serious loss in SO₂ reduction. According to the commenters, this increase in the emission limit would produce significant benefits to smaller users of coal, allowing them to purchase less expensive, higher sulfur coal. Several of the

commenters suggested that this emission limit be set at the point which minimizes both delivered coal costs and overall SO₂ emissions.

Response: As discussed in the "Summary of Regulatory Analysis" and "Revised Impacts of Alternative Sulfur Dioxide New Source Performance Standards for Industrial Fossil Fuel-Fired Boilers," various regulatory alternatives were considered and analyzed for steam generating units with heat input capacities less than 73 MW (250 million Btu/hour). These alternatives included, as suggested by the commenters, establishing an emission limit only for these smaller steam generating units. However, Section 111 of the Clean Air Act requires standards to reflect application of the "best demonstrated technology" for which costs, nonair quality health and environmental impacts, and energy requirements are considered reasonable. The final standards achieve greater emission reductions than would be achieved by an emission limit only, and the costs, nonair quality health and environmental impacts, and energy requirements of the final standards are considered reasonable. Therefore, a less stringent standard for these smaller steam generating units is not appropriate under Section 111 of the Clean Air Act.

4. Comment: Several commenters (IV-D-26, IV-D-28, IV-D-30, IV-D-40, IV-D-50, IV-D-53, IV-D-83, IV-F-1.8, IV-F-1.16) said the proposed standards should be withdrawn and a new proposal submitted that is limited to an emission limit for units larger than 73 MW (250 million Btu/hour). The commenters said that if, on reanalysis, an emission limit is found reasonable for units between 29 and 73 MW (100 and 250 million Btu/hour), that should also be submitted for further

public comment as a reproposal. Others (IV-D-10, IV-D-26, IV-D-45, IV-D-48, IV-D-62, IV-D-73, IV-F-1.12, IV-F-1.16, IV-F-1.18) agreed, saying that steam generating unit owners and operators should have the flexibility to use low sulfur fuel. Another (IV-D-76) felt that the percent reduction requirement achieves emission reductions in an inefficient way. Without a percent reduction requirement, the commenter said, an owner or operator could achieve the same emission level at a lower cost by using lower sulfur coal or oil.

Response: With several exceptions, as discussed earlier, the impacts of a percent reduction requirement were thoroughly examined and found to be reasonable within the meaning of Section 111 of the Clean Air Act for steam generating units larger than 29 MW (100 million Btu/hour). Therefore, the final standards include a percent reduction requirement for all size categories of industrial-commercial-institutional steam generating units.

5. Comment: One commenter (IV-D-28) said that if the promulgated standard includes a percent reduction requirement, limits should be set that provide maximum compliance flexibility. The commenter suggested that in order to reflect national energy security and efficiency objectives, the flexibility could be provided by a requirement in the range of 50 percent reduction. Another commenter (IV-D-99) agreed, saying that a 90 percent reduction requirement is far too stringent and not in the nation's best interest. The commenter felt that a more realistic performance standard permitting use of less expensive coal burning technologies (such as a 60 percent reduction requirement) would achieve the dual objectives of SO_2 control and increased coal use in the future.

Response: The regulatory compliance flexibility of a 90 percent compared to a lower percent reduction requirement was carefully evaluated. While it is true that lower percent reduction requirements (such as 50 percent) would allow the use of a greater number of SO₂ control technologies, this alternative must be evaluated in relation to the requirements of Section 111 of the Clean Air Act. Section 111 requires the NSPS to be established at the level achievable by the best demonstrated technology for which no unreasonably adverse cost, environmental, or energy impacts have been identified. This "best demonstrated technology" is flue gas desulfurization and fluidized bed combustion, which have been demonstrated to achieve a 90 percent reduction in SO₂ emissions. Thus, the impacts associated with achieving a 90 percent reduction as required under the final standard are considered reasonable.

To encourage the development of alternative SO₂ control technologies, a percent reduction requirement of 50 percent has been established for emerging technologies. This provision was discussed in the preamble to the proposed standards and is retained in the final standards.

6. Comment: Several commenters (IV-D-22, IV-D-26, IV-D-30, IV-D-33, IV-D-38, IV-D-43, IV-D-44, IV-D-48, IV-D-50, IV-D-53, IV-D-55, IV-F-1.6) said the requirements in Subpart Da should be the most stringent scenario for steam generating units with heat input capacities greater than 73 MW (250 million Btu/hour). They said there is no reason industrial units should be treated more stringently than utility units. Two of the commenters (IV-D-43, IV-D-48) specifically stated that a sliding scale of emission reductions, such as that provided in Subpart Da, should be applied to industrial-

commercial-institutional steam generating units firing low sulfur fuels.

Response: Direct comparison of the standard for industrial-commercial-institutional steam generating units with the Subpart Da standard promulgated in 1979 is inappropriate for several reasons.

First, the design and operating characteristics of utility steam generating units and emission control systems (covered by Subpart Da) are different from units covered under these standards. Utility steam generating units are generally much larger than affected facilities covered under these standards. A typical 500 MW electric utility unit would have a heat input capacity of 1,450 MW (5,000 million Btu/hour). This compares to 44 MW (150 million Btu/hour) for an industrial type unit, a 30-fold difference in size. Because of their large size, utility steam generating units and FGD systems are field erected and are usually custom designed for a specific site. In the case of coal, long-term fuel purchase contracts for up to 20 years are common. As a result, utility steam generating units and FGD systems can be designed to optimize site- and fuel-specific factors. Also, to handle the large quantities of flue gas produced by utility steam generating units, utility FGD systems typically consist of multiple parallel scrubber modules (typically 4 or 5 modules), with each capable of handling part of the total flue gas. To ensure operating reliability of the total FGD system, an additional FGD module is generally installed as a spare to provide backup for a module that malfunctions or is idled for preventive maintenance.

In contrast, industrial-commercial-institutional steam generating units and FGD systems are smaller and are more likely to be package units that are designed to provide the operator with maximum flexibility in future fuel purchasing. Long-term fuel supply contracts are less common with industrial applications. Industrial-commercial-institutional steam generating units and FGD systems are likely to be shop assembled based on standardized designs and have the ability to handle a wider range of fuels than typical utility steam generating units. These FGD systems generally consist of single modules without spares. Because of their smaller size, switching to natural gas or low sulfur oil during FGD system malfunctions is a viable alternative to installing spare FGD modules.

Second, at the time Subpart Da was promulgated, lime/limestone wet scrubbing was the predominant FGD technology used by utilities. Newer technologies, such as lime spray drying FGD, were still in the early stages of commercial application and concerns existed about the ability of these newer technologies to achieve 90 percent SO_2 reduction on a reliable basis. Today, a number of demonstrated FGD technologies including sodium scrubbing, lime spray drying, and dual alkali, as well as fluidized bed combustion are available for use by industrial-commercial-institutional steam generating units. Based on experience gained with these technologies during the past decade, including improved preventive maintenance programs, as well as various technical advantages of these technologies over wet lime/limestone FGD, industrial FGD systems are expected to be more efficient and reliable than the utility FGD systems were a decade ago.

Because of the many differences between industrial-commercial-institutional and utility steam generating units, it is inappropriate to conclude that the final Subpart Db standards must mimic Subpart Da.

7. Comment: Two commenters (IV-D-97, IV-F-1.4) noted that the proposed standards offered four alternative compliance methods, none of which is feasible in New York City for large-scale district steam generation. The commenters gave the following examples:

- the use of coal with scrubbers is prohibited by a ban on coal burning imposed by the City's Air Pollution Control Code;
- the use of high sulfur oil with scrubbers is prohibited because the Code does not permit the purchase, use, or storage of high sulfur fuel oil, and this alternative would be much more costly than firing very low sulfur oil to meet the same emission level.
- the option of burning natural gas is unacceptable because there is no assurance of a continuous, long-term supply;
- the use of very low sulfur (0.2 percent) oil is infeasible because oil with such a low sulfur content is not readily available on the East Coast and, even if it were available, the cost would be prohibitive compared to the 0.3 percent sulfur oil currently in use.

The commenters requested that "very low sulfur oil" be defined as 0.3 percent sulfur to provide a reasonable compliance option for their facilities.

Response: The commenter's claim that there are no feasible compliance options under the standards for sources in New York City was investigated. It is true that the use of coal, with or

without an FGD system, would likely be precluded due to the generally tight space restrictions in urban areas and waste disposal constraints. The use of high sulfur oil with an FGD system could be permitted under certain circumstances. The commenter's analysis assumed the use of a dual alkali FGD system due to suggested liquid waste disposal constraints, which would noticeably increase annualized costs over those incurred by other types of FGD systems, such as a sodium FGD system. While this may be true, the costs associated with the use of the more expensive dual alkali FGD systems are considered reasonable, as are the impacts of the standard under the situation described by the commenter.

The use of natural gas is also a less costly alternative and would probably be a more attractive compliance option for such applications in most cases. The commenter's concerns about the reliability of natural gas supplies are not borne out by current data. Natural gas availability would be expected to compare favorably to that of the low sulfur oil currently being fired by the commenter. If availability concerns remain, the source could fire natural gas with very low sulfur oil as a backup fuel to ensure continuous operation, or it could simply fire very low sulfur oil. Additionally, the final standards provide an exemption from the percent reduction requirement for steam generating units operating at annual capacity utilization factors of less than 30 percent for oil or coal. Thus, the final standards provide two options that would not require the use of an FGD system. First, natural gas could be used as the primary fuel with a backup supply of very low sulfur oil maintained for any periods of gas supply interruption. Second, if natural gas is not available or is more expensive, very low sulfur oil could be fired.

8. Comment: Some commenters (IV-D-15, IV-D-49, IV-D-55, IV-D-57, IV-D-82) said the proposed SO₂ emission limit of 86 ng/J (0.2 lb/million Btu) for an oil-fired steam generating unit without an FGD system is unrealistic. They said that at present, a residual oil with a sulfur content of 0.2 percent is not commercially available. According to the commenters, the lowest sulfur specification for commercially available oil is 0.3 percent sulfur. Two other commenters (IV-D-31, IV-D-34) said the compliance level for very low sulfur oil should be raised from 86 ng/J (0.2 lb/million Btu) to 215 or 258 ng/J (0.5 or 0.6 lb/million Btu) (equal to an oil of roughly 0.5 weight percent sulfur or less) because:
- oil with a sulfur content equivalent to 86 ng/J (0.2 lb/million Btu) is not generally available;
 - most low sulfur residual fuel used in the U.S. is manufactured by distillation of crude oils yielding 0.2 to 0.5 percent sulfur fuel;
 - it is not cost effective to desulfurize or to use FGD systems on fuel oils containing less than 0.5 percent sulfur. The incremental cost effectiveness is well over the \$2,400/Mg (\$2,200/ton) cutoff used elsewhere in this NSPS;
 - it does not seem reasonable to require construction and operation of FGD systems with low sulfur fuels when the SO₂ emissions without FGD systems are the same or even lower than when scrubbing emissions from high sulfur fuels.

Response: The basis for the SO₂ emission limit of 86 ng/J (0.2 lb/million Btu) in the proposal was to provide an alternative means of demonstrating compliance with the percent reduction requirement. The sulfur content of this oil was so low that it appeared reasonable to assume that refining the original crude oil had resulted in a 90 percent reduction in potential SO₂ emissions. This provision, therefore, was not based on an assessment of the availability of such oils, but merely on an assessment of how low the sulfur content of an oil would need to be in order to reasonably assume a 90 percent reduction in its sulfur content had already been achieved.

As a result of these comments, the basis for this provision was reviewed. A much more detailed assessment than that done at the time of proposal was undertaken to determine the means by which most very low sulfur oils are produced. This assessment concluded that most very low sulfur oils, even those as low as 86 ng/J (0.2 lb SO₂/million Btu), are not produced by desulfurization, but by distillation of very low sulfur crude oils. As a result, there is no point at which the sulfur content of an oil is so low that one can reasonably assume with some confidence that the production of this oil resulted in a 90 percent reduction in its sulfur content. Consequently, the final standards contain no provisions similar to those proposed that provide an alternative means of demonstrating compliance with the 90 percent reduction requirement.

Although the final standards do not contain these alternative provisions for demonstrating compliance with the 90 percent reduction requirement based on the sulfur content of the oil, as discussed earlier, the final standards do

exempt certain steam generating units from the percent reduction requirements. This is the case when the impacts associated with the percent reduction requirements are considered unreasonable (i.e., low capacity factor and mixed fuel-fired steam generating units, steam generating units in noncontinental areas, and steam generating units firing very low sulfur oil). These steam generating units, however, are subject to an SO_2 emission limit which, in the case of oil-fired units, is 129 ng/J (0.3 lb SO_2 /million Btu).

Unlike the 86 ng/J (0.2 lb/million Btu) emission limit provided at proposal, the 129 ng/J (0.3 lb/million Btu) emission limit for steam generating units exempt from the percent reduction requirement is based on an assessment of the emissions, costs, and availability of such oils. As cited by the commenters, this assessment found that the lowest sulfur content specification placed on commercially available oils is generally 129 ng/J (0.3 lb/million Btu). Oils with such low sulfur contents, however, are widely available. In some areas, these oils may be residual oils and in other areas they may be distillate oils ("Availability of Very Low Sulfur Fuel Oil," 1987). In either case, such oils are available and the costs associated with their use are considered reasonable. Consequently, where oil-fired steam generating units are exempt from the percent reduction requirements in the final standards, they are subject to an SO_2 emission limit of 129 ng/J (0.3 lb SO_2 /million Btu).

9. Comment: One commenter (IV-F-1.4b) questioned whether firing a very low sulfur coal with less than 90 percent removal as long as it met an 86 ng/J (0.2 lb SO_2 /million Btu) emission limit would also be acceptable. Another (IV-F-1.4c) noted that if

an oil with a sulfur content of 1 percent is fired and emissions are 86 ng/J (0.2 lb/million Btu), only 80 percent reduction has been achieved but the standard deems this acceptable. However, the commenter said, if a 1 percent sulfur coal is fired, 90 percent reduction down to 43 ng/J (0.1 lb/million Btu) is required. The commenter felt this was inequitable. Another commenter (IV-D-93) felt that anthracite should be considered a "very low sulfur coal" for compliance purposes and thus be exempt from the percent reduction requirement. The commenter contended that the Pennsylvania anthracite deposits represent the largest single coal reserve in the eastern United States which can regularly meet a 430 ng/J (1.0 lb/million Btu) emission limit. According to the commenter, this is due to a combination of low inherent sulfur content and strict preparation plant quality control, which ensures a high heating value.

Response: As discussed above, the final standards do not contain an emission limit that allows the operator of an FGD system to achieve less than 90 percent SO₂ control. For steam generating units operated at low capacity factors, located in noncontinental areas, or firing very low sulfur content oils, an emission limit must be met, but an FGD system is not required. However, for all other oil- or coal-fired units, operation of the FGD system at a 90 percent performance level is required.

10. Comment: Several commenters (IV-D-23, IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-D-55) said the precombustion coal cleaning "credit" in the proposed standards does not reflect the clear meaning of Section 111(a)(1) of the Clean Air Act. They asserted that full credit against the final percentage reduction should be allowed for any precombustion cleaning, including pulverizer rejects and flyash interactions, as was done in Subpart Da.

Response: Under both the proposed and final standards, full credit toward complying with the 90 percent reduction requirement is allowed for all types of precombustion fuel cleaning technologies, including pulverizer and flyash rejects.

Credit for sulfur removal in the coal bottom ash and flyash is achieved under the final regulation in the optional "as-fired" fuel sampling procedures under the SO₂ emission monitoring requirements. By monitoring SO₂ emissions (ng/J, lb/million Btu) with an as-fired fuel sampling system located upstream of coal pulverizers and measuring SO₂ emissions with an in-stack continuous SO₂ monitoring system downstream of the FGD or FBC system, sulfur removal credits for the coal pulverizer, bottom ash, and flyash are combined with removal achieved by the FGD system into one overall removal efficiency.

11. Comment: Some commenters (IV-D-15, IV-D-26, IV-D-30, IV-D-33, IV-D-45, IV-D-50, IV-D-53) said the proposed tracking procedure for obtaining credits toward the percent reduction requirement for precleaning oil and coal is unrealistic and incompatible with mining, refinery, and fuel blending operations. They felt that low sulfur fuel should be considered as a pretreated fuel and no pretreatment documentation should be required.

Response: As discussed earlier, review of the means by which very low sulfur oils are produced concluded that no general correlation is possible between the sulfur content of a particular oil and the amount of percent reduction (i.e., desulfurization) it has undergone. Therefore, the proposed requirements for documenting the percent reduction obtained through the pretreatment of coal and oil have been retained in the final standards. In order to obtain credit for the reduction in SO_2 emissions achieved by any fuel pretreatment process, a steam generating unit operator must be able to certify that the fuel being fired actually had undergone pretreatment and the extent to which this pretreatment reduced the sulfur content of the fuel. To this end, both a certified statement from the fuel pretreatment facility specifying the amount of sulfur removed and documentation tracking the shipment of the fuel to the affected facility are necessary. If no documentation were required, steam generating unit operators would be able to purchase fuel with a lower sulfur content and claim a pretreatment credit when no pretreatment occurred.

2.5 STANDARD FOR PARTICULATE MATTER

1. Comment: Two commenters (IV-D-37, IV-D-80) suggested that the particulate matter standards recognize the differences among oil grades and specify the oil grades to which the particulate matter emission limits apply. One (IV-D-80) said that steam generating units which burn distillate oil are capable, without any emissions control, of emitting particulate matter at a rate of less than 8.6 ng/J (0.02 lb/million Btu) heat input, and are currently required to do so in some States. Therefore, the commenter said, the particulate matter emission limit for distillate oil-fired steam generating units of 43 ng/J (0.10 lb/million Btu) is too high and should be reduced to 8.6 ng/J (0.02 lb/million Btu).

Two commenters (IV-D-64, IV-D-80) said that it is inequitable to establish a particulate matter standard that allows oil-fired units to emit at twice the rate allowed for coal-fired units [coal at 27 ng/J (0.05 lb/million Btu) versus oil at 43 ng/J (0.10 lb/million Btu)]. One commenter objected that residual oil is an inherently cleaner fuel than coal and therefore should be able to achieve at least the level of particulate matter control required for coal-fired units. The other commenter contended that the allowance of a more lenient standard for oil-fired units offers an inappropriate subsidy for the use of oil in industrial-commercial- institutional steam generating units. This commenter said that the use of electrostatic precipitators on oil-fired units would achieve substantial improvement in particulate matter control over scrubbers alone.

Response: As discussed in the Summary of Regulatory Analysis prepared for the proposed standards, data collected on the performance of wet FGD systems on residual oil-fired steam generating units demonstrate that this control system is capable of reducing particulate matter emissions from residual oil-fired units to 43 ng/J (0.10 lb/million Btu). In order to reduce particulate emissions beyond the level achieved by the scrubber, an electrostatic precipitator (ESP) would be required. Data collected from residual oil-fired units controlled by ESP's (both with and without a scrubber) showed emissions of 22 ng/J (0.05 lb/million Btu). The incremental cost effectiveness of a 22 ng/J (0.05 lb/million Btu) standard based on the use of an ESP plus an FGD system compared to the use of the FGD system alone was estimated to be more than \$11,000/Mg (\$10,000/ton). This is considered unreasonable for general application; consequently, the standard limits emissions to 43 ng/J (0.10 lb/million Btu) for oil-fired steam generating units.

Distillate oil-fired steam generating units may be capable of achieving particulate matter emission rates as low as 22 ng/J (0.05 lb/million Btu) or possibly less. However, the same emission rate will be achieved whether the standard for distillate oil is set at 43 ng/J (0.10 lb/million Btu) or 22 ng/J (0.05 lb/million Btu), because no emission control system is necessary to reduce emissions from distillate oil to these levels. Thus, it makes no difference whether the standard for distillate oil-fired steam generating units is 43 or 22 ng/J (0.10 or 0.05 lb/million Btu). Consequently, for convenience and to keep the testing and reporting requirements as simple and easy to understand as possible, the final standard limits particulate matter emissions to 43 ng/J (0.10 lb/million

Btu) for all types and grades of oil. In summary, the emission standard for oil has been set at a higher level than coal because of cost-effectiveness considerations.

2. Comment: Several commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-F-1.15) said the sodium scrubber test data presented at proposal do not support a particulate matter emission limit of 43 ng/J (0.1 lb/million Btu) for oil-fired steam generating units and are not representative of typical industrial-commercial-institutional steam generating unit performance. The commenters added that critical variables affecting scrubber performance were not recorded. Specifically, they said that site-specific information about operating factors, fuel related parameters, and scrubber parameters must be recorded and considered because they can have a significant impact on particulate matter formation and control. According to the commenters, it is impossible to extrapolate test data from a small sample population to all industrial steam generating units without consideration of these variables.

Response: The data cited in the "Summary of Regulatory Analysis" were taken from seven oil-fired steam generating units using wet scrubbers for both particulate matter and SO₂ control. The seven wet scrubbing units represented four different designs and fired oils having potential SO₂ emissions of 473 to 1,204 ng/J (1.1 to 2.8 lb/million Btu) heat input under a variety of site-specific operating parameters. Particulate matter emissions from these seven units ranged from 22 to 43 ng/J (0.05 to 0.10 lb/million Btu) heat input. Consequently, the test data clearly support a particulate matter emission limit of 43 ng/J (0.10 lb/million Btu).

2.6 NATIONAL IMPACTS

2.6.1. Fuel Market and Energy Impacts

1. Comment: Several commenters questioned the policy of encouraging the use of natural gas for industrial applications. Some (IV-D-22, IV-D-54, IV-D-60, IV-D-81, IV-D-84, IV-D-87, IV-F-1.1, IV-F-1.6, IV-F-1.11) felt that natural gas should be reserved for uses demanding a more versatile fuel supply, such as residential, institutional, agricultural, and transportation uses. Others (IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-84) said the analyses have not shown that natural gas is available, practical, and reasonably priced in all areas of the country. Several commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-52, IV-D-53, IV-F-1.16) also expressed concern that if steam generating unit owners become totally dependent on natural gas to the exclusion of other fuels, and should curtailments such as those experienced in the 1970's recur, plant closures could result due to this loss of fuel flexibility. One commenter (IV-D-31) said if prices and drilling rates remain at current very low levels, there may not be sufficient domestic production capability by 1988 to satisfy industrial and electric utility natural gas demand. Another (IV-F-1.18) asserted that no one is buying oil- and gas-fired steam generating units even with current low prices, because industry officials have no faith that oil and gas prices will remain low. Still others (IV-D-31, IV-D-33, IV-D-51, IV-D-81, IV-D-88, IV-F-1.16) said that natural gas is not available in all areas of the country, and in some places, it is available only on an interruptible basis. In addition, the commenters said that natural gas currently costs much more than coal or oil in many locations.

Response: The natural gas shortages and curtailments experienced during the 1970's were not indicative of a shortage of natural gas reserves, but were rather a response to adverse supply and demand situations. Because Federal regulation of natural gas prices kept these prices well below the costs of alternative fuels, there was a large demand for natural gas. This led to large decreases in available natural gas reserves as production exceeded reserve additions, causing regional shortages in some areas. However, with passage of the Natural Gas Policy Act of 1978, deregulating the price of most natural gas by January 1, 1985, an incentive to locate additional reserves was created and drilling increased. This increased natural gas supply and market competition with oil created a gas surplus, or "bubble." This bubble is currently estimated by both the U.S. Department of Energy (DOE) and the American Gas Association (AGA) at about 3 trillion cubic feet (Tcf). Although drilling is currently low, it is anticipated that as this bubble is used up producers will again have an incentive to continue drilling to build up reserves. The American Gas Association, as well as various reports in the literature, have predicted that gas reserves and demands will come into balance in the next couple of years.

There has been some concern among commenters that gas shortages will occur in the short term -- i.e., in the period between depletion of the gas bubble and resumption of drilling activity. According to the AGA, there are several sources of auxiliary gas supplies that could be made available on short notice (less than 12 months) to serve as a "bridge" while industry explores and develops new long-term supplies. These include Canadian and Mexican imports, uncommitted nonproducing reserves, accelerated

infill drilling (drilling into known gas fields), and liquified natural gas. According to the AGA, these sources should be more than sufficient to satisfy short-term demand during resumption of drilling activity.

Projections of natural gas demand through the remainder of the 1980's have been made by several organizations, including the AGA and the National Petroleum Council. These projections are generally within the range of 16 to 18 Tcf/year, with even lower demand expected after 1990. With a resumption of drilling activity, natural gas supplies should be more than sufficient to meet this demand. In any event, fuel switching as a result of these standards represents less than 1 percent of total U.S. natural gas consumption. Therefore, the standards will have no significant impact on overall natural gas supply and demand, and will not affect the use of natural gas for other purposes, such as residential, agricultural, or transportation uses.

While the final standards will encourage the use of natural gas to some extent, the price of natural gas relative to other fuels will have a much greater impact on fuel use than any requirements associated with these standards. Recent declines in the price of natural gas, as well as projections of continued low prices, indicate that natural gas will represent the fuel of choice in a major portion of new industrial-commercial-institutional steam generating units even in the absence of standards.

For many years, natural gas has been a major energy source for the industrial sector. A widespread transmission and distribution system has been developed which serves all

areas of concentrated industrial production and even many isolated plants. Although firm data are lacking, the largest share of new steam generating units will probably be installed in existing plants where natural gas hookups already exist. In some specific instances (such as noncontinental areas), the availability of natural gas will be limited. Therefore, an exemption from the percent reduction requirement has been granted for noncontinental areas, and facilities in these areas will be allowed to fire low sulfur fuel to meet the pertinent emission limits.

Another concern raised by commenters, that natural gas prices could become prohibitive in the future, is also not supported by the data. The AGA projects that U.S. gas prices will decline by more than 7 percent annually through 1988 and increase at about the same rate as overall inflation thereafter. These near-term price declines are expected as natural gas experiences competition from residual oil due to current low oil prices and the reaction of the gas market to recent declines in wellhead prices. As this occurs, the price advantage historically enjoyed by coal will shrink, bringing the prices of gas, oil, and coal closer together. Although delivered coal costs will remain lower than delivered gas costs, the higher capital, operating, and maintenance costs associated with firing coal will tend to make gas more attractive, especially for smaller industrial applications.

Also, an interruptible gas contract can be purchased at lower cost than a firm, noninterruptible contract. As discussed earlier, the final standard accommodates sources that choose to purchase natural gas under interruptible supply contracts and use a backup oil supply by providing an

exemption from the percent reduction requirement as long as very low sulfur oil is fired.

2. Comment: One commenter (IV-D-48) asserted that the proposed regulation, by encouraging natural gas use, directly conflicts with the Powerplant and Industrial Fuel Use Act of 1978, which states that natural gas "...shall not be used as a primary energy source in a new major fuel-burning installation consisting of a boiler...."

Response: Since passage of the Powerplant and Industrial Fuel Use Act in 1978, the national energy climate has undergone a significant transformation. Domestic natural gas reserves have increased and natural gas is no longer in short supply. Although multi-fuel capability is now an important consideration in steam generating unit design, natural gas continues to be the fuel of choice for many industrial-commercial-institutional applications. In addition, provisions were included in the Powerplant and Industrial Fuel Use Act which provide for waivers from this prohibition against the use of natural gas in cases where this would result in a substantial increase in costs. In actual practice, the Fuel Use Act has been administered in a manner which recognizes this change in energy conditions and the economic appeal of natural gas. Examination of the record of requests to the Department of Energy for waivers indicates that very few requests have been denied. In fact, repeal of major provisions of the Fuel Use Act occurred in mid-1987.

Therefore, the final standards are believed to further both national energy and environmental goals, and are consistent with past energy and environmental practice.

3. Comment: One commenter (IV-F-1.9) said that removing low sulfur coal, one of the most abundant and economical fuels, from the new steam generating unit market will guarantee an exponential increase in the cost of fuels for industrial-commercial-institutional steam generating unit operators.

Response: While competition from coal can influence the prices of gas and oil to some degree, the prices of gas and oil are primarily "driven" by other factors, such as direct marketplace competition between gas and oil, international trade regulations and foreign price controls, and domestic regulation of fuel prices. As a result, the impact of the standard is unlikely to significantly increase the costs of fuels for industrial-commercial-institutional steam generating units.

Both low and high sulfur coal can be used to meet the percent reduction requirement. Analyses of the impacts of the standards examined the total costs of generating steam, including annual fuel costs, annual nonfuel operating and maintenance costs, and levelized capital costs. By requiring a percent reduction in SO_2 emissions from all regulated fuels, these standards do not discriminate against the use of either high or low sulfur coal. In addition, the final standards allow low sulfur coal to be fired without a percent reduction requirement in "low capacity factor" coal-fired steam generating units, as discussed previously.

4. Comment: Several commenters felt that the standard conflicted with the national energy policy of encouraging coal use, an aspect that was not addressed in the proposal. Some (IV-D-40, IV-D-72, IV-F-1.19) were concerned that the policy of encouraging domestic coal use was defeated by the proposed standards. Others (IV-D-12, IV-D-26, IV-D-27, IV-D-32, IV-D-36, IV-D-39, IV-D-44, IV-D-52, IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-75, IV-D-84, IV-D-87, IV-D-96, IV-D-98, IV-F-1.12) said the proposal, by encouraging the use of natural gas and distillate oil, would interfere with our national need for increased versatility in energy sources and force the U.S. further into the vulnerable position of reliance on foreign and interruptible energy supplies. One commenter (IV-D-28) expressed the opinion that the proposal will lead to a significant change in the mix of fuels used by new facilities. The commenter felt that significant market distortions without concomitant gains for society, such as significant environmental improvements, are contrary to the National Energy Policy Plan and public policy.

Response: The revised fossil fuel price scenarios indicate that, with the recent downturn in oil and gas prices, the costs of generating steam from oil and natural gas are competitive with those of generating steam from coal. In fact, based on economic factors alone, it is expected that natural gas and, to some extent, oil will claim the largest share of the industrial-commercial-institutional steam generating unit market even in the absence of the standards. Thus, the current level of oil and natural gas prices will have much more of an impact on coal use in industrial-commercial-institutional steam generating units than the final standards. In addition, with oil and gas prices at current

levels, national energy policies originally established to encourage the use of coal have been amended somewhat, with a focus on encouraging the use of a more versatile mixture of domestic fuels. This includes domestically produced natural gas as well as coal. While the standards may cause a larger proportion of new steam generating units to fire natural gas than might otherwise do so, much of this "fuel switching" will be from oil to gas rather than from coal to gas. In any event, the total amount of fossil fuel demand by industrial-commercial-institutional steam generating units is only a very small percentage of total U.S. demand, and any changes in the fuel mix in this sector will not be sufficient to cause "significant market distortions."

5. Comment: A number of commenters questioned the effects of the standard on the industrial coal market. Several (IV-D-6, IV-D-7, IV-D-17, IV-D-26, IV-D-27, IV-D-28, IV-D-35, IV-D-36, IV-D-38, IV-D-40, IV-D-50, IV-D-52, IV-D-54, IV-F-1.11) said the proposed standards would practically eliminate coal as a viable fuel choice for new industrial steam generating units, causing displacement of 5.1 to 9 million Mg (5.6 to 10 million tons) per year of potential coal use by natural gas. Others (IV-D-14, IV-D-17, IV-D-26, IV-D-29, IV-D-38, IV-D-40, IV-D-46, IV-F-1.8) said that in addition to a reduction in the future market for coal, the proposal will result in a reduction of coal's share of the existing industrial market. According to the commenters, this will occur because many future steam generating units will be for replacement of existing capacity. They said the standards will result in the failure of coal to capture a share of this replacement market, thus losing a major portion of the existing market. The commenters claimed that by the years 2000-2020, the coal industry could face a

market share loss of approximately 45 million Mg/year (50 million tons/year), an impact that was not addressed in the proposed regulation.

Other commenters (IV-D-6, IV-D-10, IV-D-26, IV-D-28, IV-D-40, IV-D-50, IV-D-52, IV-D-53, IV-D-98, IV-F-1.12, IV-F-1.8) said the proposed rule would needlessly drive consumers away from coal, this nation's most secure and reliable energy source. They questioned this policy, saying that to remain competitive in national markets, industrial steam users must be assured a reliable supply of fossil fuel. One commenter (IV-D-96) said that a comparison of total costs (on a "per Btu" basis) for coal- and oil-fired steam generating units complying with the proposed standards shows that in order for coal to compete effectively with oil and natural gas as an industrial steam generating unit fuel, oil prices would have to rise to \$35-45/barrel. The commenter added that given current and anticipated petroleum prices, this implies that the proposed standards effectively preclude any burning of coal in new or reconstructed industrial steam generating units.

Response: The analyses of the national impacts associated with the proposed and promulgated standards focused on impacts in the fifth year following proposal of the standards. Two sets of national impacts projections were prepared prior to the June 1986 proposal. One of these was labeled the "High Oil Penetration" energy scenario, which reflected a "best estimate" of future coal, oil, and natural gas prices in 1984. Under this set of assumptions, it was projected that there would be no displacement of projected industrial coal demand in new steam generating units due to the proposed standards. For sensitivity analysis purposes, results for a

second scenario, labeled the "High Coal Penetration" energy scenario, were presented. This scenario was based on significantly higher oil and natural gas price forecasts. Under this set of assumptions, a potential 5 million ton annual displacement of industrial coal demand due to the proposed standards was projected by the fifth year following proposal.

Energy price scenarios and the national impacts analysis were updated between proposal and promulgation, using lower coal, oil and natural gas price projections. The revised national impacts analysis concluded that the promulgated standard will have a negligible effect on coal use in new industrial steam generating units over the next 5 years. Using these updated industrial fuel price projections, very little coal use is forecast in the baseline because the fuel price differential between coal and natural gas is too small to pay for the higher nonfuel costs of coal-firing. Because little coal is forecast in the baseline (based on economic considerations alone), the updated national impacts analysis indicates that the promulgated standard will have little impact on coal use in the fifth year following proposal. While it is recognized that new coal-fired steam generating units will continue to be built even with the unfavorable economics indicated by the new price projections, the selection of coal as the fuel of choice in these instances will often be based on site-specific factors or noneconomic considerations.

A few comments suggested that long-term impacts should be considered and that the annual displacement of industrial coal demand due to the proposed standards could increase to approximately 45 million Mg (50 million tons) by the years

2000-2020. The concern of these commenters was that existing coal-fired steam generating units will gradually be replaced by oil/gas-fired steam generating units, resulting in an absolute decline in industrial steam generating unit coal use. Recent data suggest, however, that the life of many existing steam generating units is being extended and that those units that are replaced due to poor conditions or inadequate capacity are generally replaced by new units firing the same fuel as the existing unit.

However, the most important implication of the national impacts analysis is that in nearly all of the sensitivity cases evaluated, and certainly in the most recent analyses reflecting lower oil and natural gas prices, it is the relatively low prices for oil and gas, not the final standards, which may lead to reduced coal use in new (including replacement) steam generating units. Hence, if the absolute level of industrial coal use declines in the future, it is more likely to be due to low oil and natural gas prices than to the final standards.

6. Comment: One commenter (IV-D-28) expressed concern about any regulation that discourages coal use, unless some degree of assurance can be offered that the exodus from coal will not be to oil. The commenter said overly stringent coal regulations, which discourage coal use, send an undesirable signal to the marketplace that the Administration does not place a high priority on reducing oil imports. The commenter added that this discourages technology development in the private sector, and could encourage accelerated escalation of oil prices.

Response: The promulgated standards include regulations for oil combustion as well as coal combustion. Because the same 90 percent reduction requirement is generally being applied to both coal and oil combustion, it is expected that any "exodus" from coal would not be to oil, but to natural gas. Under standards requiring the achievement of a percentage reduction in SO₂ emissions from both coal- and oil-fired steam generating units, natural gas will tend to be more competitive than oil in new steam generating units. If anything, the standards could reduce the use of imported oil in new steam generating units in favor of domestic supplies of natural gas and, as a result, are unlikely to result in any escalation of oil prices.

Even in the unlikely event that some exodus from coal to oil occurred, it would represent only a very small fraction of the current oil market in the U.S. The national impacts analysis is based on the assumption that sales of new industrial-commercial-institutional steam generating units over the next 5 years will result in total annual fossil fuel consumption of 525 PJ (498 trillion Btu). This represents less than 2 percent of the total current U.S. oil market (about 32,500 PJ or 31,000 trillion Btu per year).

7. Comment: Two commenters (IV-D-22, IV-F-1.6) stated that the Clean Air Act mandates the examination of energy impacts, which were not fully considered in developing the standards.

Response: The energy impacts associated with the promulgated standards were thoroughly examined, as discussed above and in "Revised Impacts of Alternative Sulfur Dioxide New Source Performance Standards for Industrial Fossil Fuel-Fired Boilers." The impacts of the proposed standards were also thoroughly

examined and discussed in the preamble to the proposed standards and in the "Summary of Regulatory Analysis." These impacts are considered reasonable in light of the significant emission reductions achieved by the standards.

8. Comment: One commenter (IV-D-28) said that if the margin between oil and coal prices becomes very large, as might occur in a supply disruption, then retrofitting of oil and gas steam generating units with coal might be necessary to maintain industrial production. The commenter asserted that the energy impacts of the proposed regulation in such an eventuality were not evaluated.

Response: In assessing the impacts of a standard, it is not possible to quantitatively address potential impacts that could occur under every possible eventuality. A number of scenarios including various ranges of fuel prices were addressed in the impacts analysis. Given current expectations with respect to relatively low oil and gas prices, a supply disruption forcing massive conversions to coal is not considered likely.

Additionally, from a technical point of view, the vast majority of gas- and oil-fired industrial-commercial-institutional steam generating units are package units specifically designed to accommodate gaseous or liquid fuels. These steam generating units physically cannot be converted to fire coal.

9. Comment: One commenter (IV-D-98) noted that a senior interagency group, under the leadership of the Department of Energy, is reviewing the question of energy sources and national security. The commenter said the findings and

recommendations of this group should be considered prior to promulgating standards.

Response: The report issued by this group, "Energy Security - A Report to the President of the United States," was published by the Department of Energy in March 1987. The primary national energy security concern identified and discussed in this report was a means of limiting the increased use of imported oil and encouraging the use of domestically produced fuels, such as coal and natural gas. The final standards treat coal and oil in equivalent fashions and are expected to discourage the use of oil in favor of natural gas. Therefore, these standards are not considered to be in conflict with national energy policies or the report issued by this group and referred to by the commenter.

2.6.2 Energy Scenarios

1. Comment: Several commenters (IV-D-6, IV-D-28, IV-D-40, IV-D-50, IV-D-52, IV-D-85) said the fuel price scenarios used to evaluate impacts of the proposed standards (for both high coal and high oil penetration) are unrealistic based on today's environment. In particular, the commenters said, the high coal penetration scenario, which is used as the basis for impacts on coal-fired steam generating units, significantly overestimates the number of coal-fired units that will be built, given the relatively small current price differential between coal and natural gas. This has resulted in an exaggerated and unrealistic estimate of the impacts of the standard on coal firing. One (IV-D-28) said the baseline use of coal, which was small in the analysis, could drop to near zero with current price projections. The commenter said this would reduce the projected benefit and cost of the proposed regulation.

Response: The high coal penetration scenario was analyzed in the proposed regulation in response to concerns that the "most likely" (high oil penetration) scenario could underestimate the impacts of the standard on coal-fired steam generating units. Therefore, it was structured as a "conservative" estimate of the impacts that could occur if more coal-fired units than expected were built.

As a result of changes in fossil fuel prices since early 1986, the energy prices were revised to evaluate potential changes in impacts. As expected, the projected amount of coal use in new industrial-commercial-institutional steam generating units decreased to almost zero. The revised energy price scenarios and their potential impacts are discussed in "Revised Impacts of Alternative Sulfur Dioxide New Source Performance Standards for Industrial Fossil Fuel-Fired Boilers."

Despite these projections of little or no coal use in industrial-commercial-institutional steam generating units, some coal use will occur. Therefore, impacts were reassessed for coal-fired steam generating units. This reassessment indicated that the impacts associated with the final standards were essentially the same as those cited at the time of proposal in terms of costs and emission reductions from individual coal-fired steam generating units. These revised model steam generating unit impacts are discussed in "Impact of New Fuel Prices on the Costs and Cost Effectiveness of SO₂ Emission Control of Industrial Coal- and Oil-Fired Model Steam Generating Units."

While the national impacts of the final standards on coal-fired steam generating units could be lower than those associated with the "high coal penetration" scenario discussed at proposal, SO₂ emissions from coal-fired steam generating units are still significant on an individual steam generating unit basis. Because the costs of controlling emissions from these steam generating units are considered reasonable in light of the resulting SO₂ emission reductions, the final standards will apply to coal-fired steam generating units.

2. Comment: One commenter (IV-F-1.2) said the Industrial Fuel Choice Analysis Model (IFCAM) cost projections are outdated and far too high. The commenter asserted that fuel costs are only 50 percent of what they were expected to be and are not likely to rise to that higher level. Another (IV-D-28) suggested that, due to the high oil price projections, the energy scenario may have led to the proposal of inappropriate standards. In fact, the commenter said, alternative energy assumptions may lead to the conclusion that no revision of the current standards is warranted. Therefore, the commenter said, a greater range of energy prices should be considered in order to bracket likely energy impacts. One commeter (IV-D-44) suggested that the new energy scenarios should include an analysis of the risk of energy price and supply volatility. Two other commenters (IV-D-31, IV-D-76) also agreed that lower crude oil prices than those assumed in the analysis should be used. They said that changes in fuel price assumptions would reduce the price differential between low and high sulfur oil, with a concomitant deterioration in the attractiveness of FGD.

Response: As discussed above, new industrial fuel price forecasts were prepared based on lower crude oil prices than those used in the proposal. These new forecasts include lower projections of industrial coal, natural gas, residual oil, and distillate oil prices. The national impacts analysis has been revised using these new industrial fuel price forecasts.

The updated national impacts analysis includes a variety of scenarios based on a wide range of future crude oil prices in order to address the risks of energy price and supply volatility. These revised national impacts analyses are detailed in "Revised Impacts of Alternative Sulfur Dioxide New Source Performance Standards for Industrial Fossil Fuel-Fired Boilers."

The use of alternative energy price assumptions to evaluate the national impacts of the final standards under a variety of energy scenarios did not result in identification of any significant adverse impacts, nor did it alter the previous conclusions that the standards are appropriate and reasonable. While it is true that the differential in high and low sulfur oil prices is smaller than that identified at proposal, resulting in somewhat greater costs associated with the use of FGD compared to very low sulfur oil, the costs and benefits of the final standards are still considered reasonable.

3. Comment: One commenter (IV-D-28) said that a spectrum of possible energy scenarios should be evaluated and new assumptions and analyses should be subject to public review and comment prior to further action on this rulemaking. The commenter suggested that the following three scenarios should be considered:

- The cost of oil could become enough lower than the marginal price of gas that the response to regulation would not be switching to gas, but to controlling emissions from firing oil. According to the commenter, this would reduce benefits, but probably increase costs and result in less favorable cost-effectiveness ratios.
- If the gas prices are projected to be lower than oil prices until after the year 2000, almost all steam generating units would use natural gas, with or without a regulation, and there would be no environmental justification for the current rulemaking. The commenter said this scenario, as well as a low oil price scenario, should be evaluated using IFCAM.
- Legislation now under consideration by Congress would repeal provisions of the Fuel Use Act which authorize special exemptions for industrial steam generating units undergoing coal retrofits. The commenter said EPA has not published any analysis of such a scenario where such massive conversions to coal occur and are subject to NSPS. Should these modifications be subject to NSPS, the commenter said, a third energy scenario is created for evaluation.

The commenter suggested that the first two scenarios (gas more expensive than oil, oil more expensive than gas) be considered the basis for judging the need and benefit of the standard. The commenter also said that the third scenario,

while less likely, needs to be considered because it is possible, and because if it occurs, standards based only on the first two scenarios could have unacceptable energy and economic impacts.

Response: Although considered unlikely, as part of the revised (post-proposal) national impacts analysis using new industrial fuel price projections, two scenarios were examined where gas is more expensive than oil. With these scenarios, there is some switching to gas under the final standards, but many units choose to continue to fire oil. Emission reductions associated with the final standards are substantial and the national average cost effectiveness of the final standards compared to the baseline for these two scenarios remains in the same range as those presented at proposal in the "Summary of Regulatory Analysis."

In addition, a scenario was also examined where gas prices are projected to be lower than oil prices until after the year 2000. Under this scenario, almost all steam generating units would use natural gas, with or without a regulation. The total benefits and total costs are significantly lower than the estimates published with the June 1986 proposal. However, these results do not mean that there is no environmental justification for the current rulemaking. Even under this scenario, the benefits associated with the final standards are expected to outweigh their costs.

It has also been suggested that the analysis consider a scenario where massive conversions to coal occur and are subject to NSPS. As mentioned earlier, it is not possible to examine every conceivable energy scenario. This scenario

of massive conversions to coal is not considered reasonable given current expectations with respect to future oil and gas prices. Furthermore, as also discussed earlier, energy scenarios characterized by high coal use in new industrial-commercial-institutional steam generating units were examined prior to proposal and the impacts associated with standards requiring a percent reduction in emissions were considered reasonable under these scenarios.

4. Comment: One commenter (IV-D-28) said projections of national impacts should be made to later years, perhaps at 5-year increments to the year 2000. According to the commenter, this would better reflect the impacts of alternative regulations and permit more reasoned selection of standards. The commenter said that such longer term projections, for example, were made to support the proposal of the electric utility NSPS. The commenter added that the effective life of the standards in terms of the number of sources that will be subject to the standards, the length of time and progress of technology required before a standard will be revised, and the operating life of the affected facilities, requires a longer time period to be analyzed than that provided in the proposal.

Response: The national impacts associated with the standards were projected for the fifth year following proposal of the standards (i.e., 1990). This 5-year period allows projection of impacts with a greater degree of confidence than would be possible under longer time periods. Projections of impacts under longer time periods would lead to increases in projected costs as well as projected emission reductions. The balance, however, between these costs and the projected emission reductions would be

unlikely to change significantly. As a result, judgments regarding the reasonableness of the final standards would not change. In addition, the Clean Air Act provides for review of standards every 4 years. Therefore, impacts of these standards will be updated and reassessed in the future during the regular review process.

5. Comment: Two commenters (IV-D-23, IV-D-98) said that even though the Agency indicated that it intends to update its energy price scenarios between the time of proposal and promulgation of the standards to determine whether the costs, emission reductions and cost effectiveness of the proposed rule will be altered significantly, such an update is required prior to proposal of any standard to provide an adequate opportunity for notice and comment.

Response: The revised energy price scenarios and national impacts analysis were entered into the docket for this rulemaking and distributed to industry trade associations and other interested groups. The results of these new analyses did not significantly alter any of the conclusions drawn from the analyses supporting the proposed standards; therefore, a formal period of public comment was not judged to be necessary.

2.6.3 New Steam Generating Unit Population Impacts

1. Comment: Several commenters felt that the increase in total industrial-commercial-institutional steam generating unit population was overestimated in the analyses. Some (IV-D-22, IV-D-26, IV-D-28, IV-D-30, IV-D-50, IV-D-53, IV-D-96, IV-F-1.2, IV-F-1.6, IV-F-1.14) said this overestimation could be as much as double the number of new

units that may actually materialize by 1990. According to the commenters, the market for steam generating units has declined by 50 percent in the last 9 years, and the new capacity ordered each year is only about 0.8 percent of existing installed capacity. Also, the commenters claimed that 70-80 percent of "new" units installed are actually replacing existing capacity, rather than 27 percent as estimated in the proposal. Therefore, the commenters said, the overall effect of the standard on air quality improvement was vastly overstated.

One commenter (IV-D-91) indicated that industry-wide replacement of existing capacity could be substantially higher than 75 percent of steam generating unit sales. This was based on the commenter's observation that between 1977 and 1983, only 21 new "grass roots" plants were constructed in the energy intensive industries identified by SIC Codes 22 (textile), 26 (pulp and paper), 29 (petroleum), and 33 (primary metals), whereas over this same period, over 2,500 industrial watertube steam generating unit orders were placed.

Response: The projections of new steam generating unit installations used in the national impacts analysis were derived from estimates of future energy consumption in the industrial sector by the Department of Energy and are higher than those made by other organizations, such as the American Boiler Manufacturers Association (ABMA). It is also true that steam generating unit sales have decreased and stabilized since the 1970 levels, and some new units are replacements for existing units. Thus, emission reductions as well as costs attributed to the proposed standards may be overestimated. However, this overestimation does not

significantly influence the overall balance between the costs and benefits or the cost effectiveness of the standard. Even if fewer steam generating units are built than projected, the SO₂ reductions achieved by the standard are still considered significant. Also, while steam generating unit sales are lower than the 1970 levels, new units are being built and will continue to be built in the future. As more and more units are constructed, further SO₂ reductions will be achieved by the promulgated standards. The cost, environmental, and energy impacts of the final standards, therefore, are considered reasonable, even assuming smaller population growth projections.

In response to comments concerning the proportion of new steam generating units that are replacements for existing steam generating units, a survey of steam generating units constructed between 1981 and 1984 was conducted. The results of this survey are discussed in "Survey of New Industrial Boiler Projects - 1981-1984" (EPA-450/3-87-006). This survey indicated that about 50 percent, rather than 70 to 80 percent, of new steam generating units were for replacement of existing steam generating units. Assuming recent declines in the price of oil and natural gas result in a curtailment of new steam generating units installed for the purpose of switching from firing oil or gas to firing coal, the percentage of new steam generating units sold as replacements for existing units will be even lower.

2. Comment: Several commenters expressed concern that the standard would discourage the replacement of existing steam generating units with new, less polluting units. One (IV-D-23) said that a standard providing an incentive to keep such old,

"grandfathered" units in service is poor policy. Several (IV-D-52, IV-D-62, IV-D-66, IV-D-75, IV-D-78, IV-D-81, IV-D-87) said this disincentive to install new units would be caused because the standard increases the costs of new units, makes their operation less reliable because of the effects of scrubber operation, and requires reliance on uncertain natural gas for backup fuel. According to the commenters, industrial operators cannot take such risks and likely will continue to operate older, existing units, thus making the standards environmentally counterproductive. Another commenter (IV-F-1.12) said that the proposed standard will further depress the already sluggish industrial-commercial-institutional steam generating unit market, causing research and development in the area of new steam generating unit design and efficiency to slow drastically.

Response: The steam generating unit sales market is smaller than it was in the mid-1970's, but this is due more to sluggish industrial growth and the depressed nature of the manufacturing sector than any existing or planned environmental standards. According to steam generating unit sales data compiled by ABMA, sales of industrial-commercial-institutional steam generating units peaked in 1974, dropped thereafter, but appear to have leveled off in the last couple of years.

New steam generating unit purchases can be divided into two categories: discretionary, meaning the purchase could be deferred if economic or other factors changed, and nondiscretionary, meaning a new unit must be installed. Discretionary steam generating unit purchases could be discouraged by environmental requirements. As discussed

above, a survey of new steam generating units ordered between 1981 and 1984 indicated that nondiscretionary installations accounted for about half of the new steam generating unit projects surveyed. These installations are expected to be neither discouraged nor delayed by an NSPS.

The survey results also indicated that many of the "discretionary" installations were relatively insensitive to cost changes. Nearly three-fourths of all respondents indicated that the discretionary projects would have proceeded as designed if costs increased by up to 20 percent. In most cases, the percent reduction requirement would increase costs by less than this amount; therefore, the standards would not influence construction of most steam generating unit projects.

The use of an FGD system, if properly designed, constructed, operated, and maintained, should not reduce the overall reliability of the production unit.

Although natural gas availability is not expected to be a problem, reliance on natural gas as a backup fuel is not mandatory. The final standards also accommodate the use of low sulfur oil as a backup fuel in steam generating units as long as oil use does not exceed 30 percent of the annual rated heat input capacity of the steam generating unit. Consequently, the standards should not significantly promote the continued operation of older existing steam generating units, should not depress the sales of steam generating units, and should not reduce new steam generating unit research and development efforts.

3. Comment: Five commenters (IV-D-6, IV-D-28, IV-D-40, IV-D-50, IV-D-52) were concerned that, because the Clean Air Act mandates compliance as of the date of proposal of standards, the uncertainty inherent in the post-proposal period combined with the expenses associated with the percent reduction requirement could cause costly project delays and, in some cases, abandonment of new steam generating unit projects.

Response: The applicability date of new source performance standards is established by the Clean Air Act [Section 111(a)(2)]. The purpose of proposed standards is to notify new source owners and operators of the requirements that may apply to sources commencing construction after the date of proposal. Although the commenters did not submit any specific examples or information to support their opinion, it is possible that some new steam generating unit construction projects could be delayed until the final standards are published. Any delays that might result, however, should be only temporary. Also, the promulgation of these standards is mandated by a court-ordered promulgation date, which is a matter of public record. Therefore, there is no uncertainty related to completion of a final standard in this case.

4. Comment: One commenter (IV-F-1.2) said the forecast of new coal-fired steam generating units is overly optimistic. At most, the commenter said, 10 to 15 new coal-fired units in the size range between 29 and 73 MW (100 and 250 million Btu/hour) have been ordered annually over the last few years. Another (IV-D-99) said that very few coal-fired steam generating units are being sold today, due to their higher capital and nonfuel operating costs and the current small price differentials between coal, oil, and natural gas. The commenter asserted that this situation is not likely to

change in the near future, and expressed the concern that the NSPS would apply additional negative pressure on the new coal-fired steam generating unit market.

Response: The national impacts analysis was recently revised using lower projections of oil and gas prices. This revised national impacts analysis shows essentially no demand for new coal-fired industrial-commercial-institutional steam generating units, even in the absence of standards, due to the competitive prices of oil and gas. Thus, future oil and gas prices are of much more significance in determining future coal use in new industrial-commercial-institutional steam generating units than the final standards.

In practical terms, however, new coal-fired steam generating units will be ordered and installed in the future. While it is possible that some steam generating unit operators contemplating installing a new coal-fired unit would elect to use natural gas instead as a direct result of the standards, the amount of "fuel switching" from coal to gas is expected to be minimal due to factors favoring the use of coal in those situations where coal is selected.

2.6.4 Emissions Impacts

1. Comment: Many commenters (IV-D-6, IV-D-10, IV-D-14, IV-D-26, IV-D-28, IV-D-29, IV-D-30, IV-D-35, IV-D-36, IV-D-40, IV-D-44, IV-D-45, IV-D-48, IV-D-50, IV-D-52, IV-D-53, IV-D-58, IV-D-62, IV-D-66, IV-D-73, IV-D-74, IV-D-84, IV-D-96, IV-D-98, IV-D-99, IV-F-1.12) felt that without an option to use compliance coal, steam generating unit operators will have less economic incentive to install new units, thus inhibiting the replacement of old, existing high sulfur

fuel-fired units. The commenters said this would inhibit the gradual reduction in emissions that is currently taking place and must be taken into account when calculating the net emission reductions due to the proposed standard.

One commenter (IV-D-62) further stated that plants with both new and existing steam generating units will choose to operate older units with higher emissions during maintenance or malfunction periods of the FGD system on the new unit, resulting in an increase in emissions. If they were allowed to continue operation of the new steam generating unit firing low sulfur coal, the commenter said, overall emissions would be lower.

Response: To assess the impacts of the standard on steam generating unit replacement, a survey was conducted of all new industrial steam generating unit projects undertaken between January 1981 and August 1984. Responses were received on 168 new projects, encompassing a total of 229 new steam generating units. Of these, 151 steam generating units were in the regulated size category and formed the basis for the analysis discussed below. Comparison with steam generating unit sales data collected by ABMA indicated that these units represent almost all of the industrial steam generating units in this size category sold between 1981 and 1984.

The results of the survey indicate that about 50 percent of the new industrial steam generating unit projects undertaken during the timeframe surveyed were nondiscretionary and would be expected to be completed regardless of the requirements of the NSPS. The remainder were discretionary installations and could be affected by regulatory requirements. However, the survey found that

nearly three-fourths of all projects would have proceeded as designed even if project costs increased by 20 percent. Therefore, while some projects could be affected by the NSPS, most of the new steam generating unit installations would remain viable, since the NSPS will generally increase costs for new steam generating units by less than 20 percent.

The effect of replacing existing steam generating units on overall SO_2 emissions was also analyzed in this survey. Analysis of SO_2 emissions before and after installation of new steam generating units found that although the new coal- and oil-fired steam generating units generally emit less SO_2 per million Btu of fuel fired than the existing (replaced) steam generating units, the total annual emissions from plants installing new steam generating units increased by roughly 70 percent. This increase results from 1) installation of new steam generating capacity that is not replacing existing units, 2) replacement of existing units with new units that are significantly larger, 3) fuel switches from natural gas and oil to coal, and 4) continued operation of the existing steam generating units, which were reportedly replaced by new units, although at reduced load.

A large portion of the emissions increase was due to steam generating units installed either to switch base fuel (usually from gas or oil to coal) or to cogenerate steam and electricity. Because these types of projects are more vulnerable to cancellation based on cost considerations than projects undertaken for other reasons, calculations were also made excluding these types of projects. Even without these significant sources of SO_2 emissions, total emissions

at plants installing new steam generating units increased by roughly 20 percent.

These results indicate that the replacement of existing steam generating units does not appear to result in any "natural" decrease in overall SO₂ emissions from this source category, as suggested by the commenters. As a result, for the reasons discussed above, the standards are not expected to significantly discourage the replacement of existing steam generating units, nor will they result in an increase in SO₂ emissions.

While it is possible that plants with both new and existing steam generating units would operate the existing units during periods of FGD malfunction, this should not significantly affect overall emissions. Periods of malfunction should be infrequent and temporary occurrences in a well operated and maintained system.

2. Comment: Five commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-D-81) said that because as much as 80 percent of the projected "new" steam generating unit population will actually be replacement units, they will not constitute new sources of SO₂ emissions. They stated that by including these emissions in the analysis, the actual "new" emission reductions resulting from the proposed standards were overestimated.

Response: As discussed above, a survey of new industrial steam generating unit projects undertaken between 1981 and 1984 indicates that only about 50 percent of new steam generating units were installed to replace existing capacity, rather than 80 percent. Emissions from all new steam generating

units (including those that replaced existing steam generating units) were correctly included as "new" capacity emissions in the impacts analyses. The SO₂ emission reduction attributed to the NSPS is a reduction in emissions from new steam generating units compared to baseline emissions that would occur from those new units in the absence of the NSPS. Because new industrial-commercial-institutional steam generating units are a major source of SO₂ emissions, regardless of whether they are replacement or "new capacity" units, they are covered by the final standards.

3. Comment: Three commenters (IV-D-12, IV-D-39, IV-D-99) expressed concern that the high compliance costs would force the construction of large numbers of smaller steam generating units which will not be subject to the standards, thereby increasing emissions and increasing problems for future regulation of these sources.

Response: Although this may be the case in a few situations, in most cases it would be more expensive to build and operate two or more smaller steam generating units than one larger one, even with the added SO₂ control costs associated with the larger steam generating unit. In any event, development of standards for steam generating units less than 29 MW (100 million Btu/hour) heat input capacity is currently underway, and their issuance will, in effect, eliminate any temporary incentive of this nature.

4. Comment: One commenter (IV-F-1.2) stated that as much as 50 percent of what is referred to as "industrial" steam generating units are actually purchased by institutional or commercial installations for heating and are used at capacity

utilization rates far lower than industrial operations. According to the commenter, institutional steam generating units are operated only during the heating season, and even then they rarely have more than 80 percent of full load, so the total capacity utilization, and the resulting SO₂ emissions, are much lower than those for industrial steam generating units. Therefore, the commenter said, the emissions impacts of the proposed standards have been overestimated.

Response: Data on new steam generating unit sales between 1979 and 1985, taken from Power magazine, listed 20 units with heat input capacities greater than 29 MW (100 million Btu/hour) that were ordered for institutional or district heating purposes over this period. According to Power, the total number of steam generating unit orders was 205. Therefore, during this period, institutional and district heating systems represented only 10 percent of new steam generating unit orders in this size range. Even this figure, however, may be too high, because a disproportionately large number of units (12) were sold to Federal military installations. The reason for this large number of Federal orders is not known, but the sales may have resulted from a Department of Defense directive to reduce steam generating unit consumption of oil for national security reasons. If these installations are excluded from the figures because they are non-recurring, the institutional and district heating systems represent only about four percent of new steam generating unit sales over this time period. This is roughly comparable to information from the Department of Energy for new steam generating units ordered between 1977 and 1981, which indicated that 22 out of approximately 400 orders were for institutional or district heating purposes.

There is no reason to expect this percentage to increase significantly in future years. Therefore, commercial and institutional steam generating units are expected to represent only a very small percentage of all steam generating units subject to this NSPS, as discussed in the proposal.

In any event, an exemption from the percentage reduction requirement has been granted for steam generating units with capacity utilization factors for coal or oil of less than 30 percent. Therefore, any commercial and institutional steam generating units that would be operated below this level would not be required to install an FGD or FBC system, but must meet certain emission limits for SO₂.

5. Comment: Several commenters questioned the baseline emission levels used in the analyses. Two (IV-D-28, IV-D-32) said that the baselines in both the model boiler analysis and IFCAM do not reflect existing new source review regulations or PSD permits. This resulted in overestimating the probable SO₂ reduction of the proposal by over 90 percent. According to the commenters, the actual new source requirement for Eastern States is 688 ng/J (1.6 lb/million Btu), and for Western States is 516 ng/J (1.2 lb/million Btu). Therefore, the commenters said, these are the maximum reasonable levels for projecting future baseline emissions. One commenter (IV-D-28) further stated that the mean State Implementation Plan (SIP) values for baseline emissions from steam generating units with heat input capacities less than 73 MW (250 million Btu/hour) should be 1,334 ng/J (3.1 lb/million Btu) for coal and 817 ng/J (1.9 lb/million Btu) for oil.

Commenters IV-D-28 and IV-D-96 added that under the proposed regulations, the net effect of the proposal was calculated

in the IFCAM analysis to be an SO₂ emission reduction of 211,000 Mg/year (232,000 tons/year) under the high oil penetration scenario or 269,000 Mg/year (296,000 tons/year) under the high coal penetration scenario. Using the same analytic approach, but a baseline based on recent new source review practices (as discussed above), would yield a net emissions change of 109,000 Mg/year (120,000 tons/year) under the high oil penetration scenario or 149,000 Mg/year (164,000 tons/year) under the high coal penetration scenario. Therefore, according to the commenters, use of an incorrect baseline in the IFCAM analysis led to overestimating emission reductions by 81-93 percent. The commenters said that simply assuming the correct emissions baselines of 688 ng/J (1.6 lb/million Btu) in the East and 516 ng/J (1.2 lb/million Btu) in the West reduces the probable environmental benefit of the regulations to a reduction of less than 0.5 percent of national SO₂ emissions in 1990.

Response: Emission levels established under PSD and NSR programs are determined on a case-by-case basis and reflect local and/or site-specific conditions. Because the limits are site-specific, they cannot be predicted with certainty.

The "baseline" emission levels used in the IFCAM analysis are actual SIP emission levels applicable in each Air Quality Control Region (AQCR) throughout the country. The AQCR-SIP levels represent the minimum level of control imposed on new units. The use of this minimum level of control as the baseline for purposes of analysis produces "upper limit" estimates of the cost impacts associated with the standards and, therefore, ensures that these costs are not underestimated. It is true that using more stringent

baselines (such as those reflected in PSD and NSR programs) would result in smaller emission reductions attributable to the standards. The costs attributable to the standards, however, would also be lower since the baseline annualized costs would increase to account for the additional PSD/NSR compliance costs. For example, as shown in the Summary of Regulatory Analysis, if an emission limit of 520 ng/J (1.2 lb/million Btu) was established as the "baseline" level, the annual baseline emissions would be 340 Mg/year (370 tons/year) for a 44 MW (150 million Btu/hour) unit in Region V. Total annualized costs under the baseline would increase from \$6,160,000 to \$6,340,000. More importantly, however, changing the baseline would not change any of the incremental impacts. Incremental impacts were used as the primary indicator of the reasonableness and effectiveness of the various regulatory alternatives. The baseline emission rates suggested by the commentor are reasonable, but even if used in the analysis, would not have changed the conclusion that the standard is reasonable.

6. Comment: One commenter (IV-D-48) asserted that 90 percent SO₂ reduction by FGD was not achievable when firing low sulfur coal and the 90 percent reduction requirement will force units to burn higher sulfur fuels in order to meet the percent reduction requirement. Therefore, the commenter said, the actual emission rate under 90 percent reduction standard could be greater than that which would result from the use of a low sulfur fuel with a less stringent, 70-90 percent "sliding scale" reduction requirement.

Response: The standards will not "force" steam generating unit operators to purchase high sulfur fuels. The percent reduction requirement is achievable on both high and low sulfur fuels, and the choice of fuel will likely depend more

on local availability and other site-specific factors than on the requirements associated with the NSPS. Thus, a sliding scale will not result in lower SO₂ emissions.

2.7 COST OF THE STANDARD

2.7.1 General

1. Comment: Several commenters felt that the cost analyses associated with the proposed standards were deficient or inaccurate:
 - A. Five commenters (IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-84) said that the use of capital cost estimates rather than actual data was a major deficiency.
 - B. These same commenters said that the use of significantly lower capital cost estimates per unit of heat input for industrial steam generating units as compared to utility steam generating units (i.e., failure to consider economies of scale) resulted in the capital costs being greatly underestimated.
 - C. Several commenters (IV-D-6, IV-D-28, IV-D-35, IV-D-40, IV-D-44, IV-D-50, IV-D-52) said that the cost estimates did not adequately reflect problems associated with sludge disposal.
 - D. These commenters also said that problems associated with the reliability of SO₂ control technology were not considered in developing cost estimates.
 - E. Six commenters (IV-D-6, IV-D-27, IV-D-28, IV-D-40, IV-D-50, IV-D-52) stated that the cost estimates did not reflect the coal transportation cost penalties that are likely to be incurred by smaller coal users. The commenters said these penalties are incurred due to the inability of smaller users to obtain volume discounts, and should be included in compliance cost estimates for these steam generating units.

- F. Two commenters (IV-D-22, IV-F-1.6) said that the cost analyses did not allow for manufacturers' profit margins.
- G. One commenter (IV-D-28) said that the high emissions baseline used in the cost analysis resulted in underestimating the cost effectiveness of the standard for many steam generating unit categories. The commenter stated that using more reasonable baseline levels of 516 and 688 ng/J (1.2 and 1.6 lb/million Btu), cost effectiveness ratios for small coal-fired units would be \$2,200-\$2,750/Mg (\$2,000-\$2,500/ton), while the model steam generating unit ratios in the analysis were roughly \$880-\$1,300/Mg (\$800-\$1,200/ton). According to the commenter, this discrepancy would be even greater in the IFCAM analysis, which results in an average cost effectiveness figure for all steam generating units of \$150/Mg (\$140/ton).

Response: A. The cost estimates used to assess the impacts of various alternatives were generated from cost algorithms developed from data obtained from vendors. The validity of the cost algorithms was examined by comparison with costs associated with actual installations. The agreement between these algorithms and actual installations was generally found to be very good -- well within the general criterion of ± 30 percent which is normally associated with "budget cost" estimates. Validity of the costs used in the cost analyses was also confirmed by statements from several commenters, including some industry trade associations. This does not mean that the cost estimates generated by the cost algorithms will agree in every case with actual installed costs. Unique design requirements related to

site-specific factors may well cause actual costs to be higher or lower than those generated by the cost algorithms used in the cost analyses. The costs generated by the cost algorithms, however, are considered representative of the costs associated with installation and operation of steam generating units and emission control systems.

- B. The cost analyses assessed the costs associated with various emission control requirements for steam generating units as small as 29 MW (100 million Btu/hour) heat input capacity and as large as 117 MW (400 million Btu/hour) heat input capacity. Costs were also assessed for units of 44, 58, and 73 MW (150, 200 and 250 million Btu/hour). Consequently, the effects of "economies of scale" were considered in the cost analyses. For example, the capital cost of SO₂ control for a 29 MW (100 million Btu/hour) steam generating unit firing bituminous coal is approximately \$10.8 million. For a 117 MW (400 million Btu/hour) steam generating unit, the capital cost of SO₂ control is approximately \$34.6 million. Therefore, while the capacity of the second unit is four times the capacity of the first, the cost increases only by a factor of 3.5.

In addition, the capital cost estimates were based on vendor quotes for industrial, not utility, steam generating units. As discussed above, these costs have been confirmed by comparison with costs associated with actual installations and are considered representative of industrial SO₂ control systems in general.

- C. Sludge disposal costs were included in the cost analyses. The costs reflect the typical costs associated with off-site land disposal of sludges from emission control systems. These costs were based on information provided by steam generating unit vendors and operators, and are considered representative of sludge disposal costs in general. They may, however, be lower or higher than actual costs experienced at specific locations where unique or site-specific requirements may apply.
- D. The cost analyses assumed, based on operating data from a number of flue gas desulfurization (FGD) systems on industrial steam generating units, that FGD systems are capable of 95 percent reliability with proper design, operation, and maintenance. The cost analysis, therefore, considered control system reliability problems and examined various approaches to reducing emissions during periods of control system malfunctions. These approaches ranged from the use of spare absorber modules to the firing of very low sulfur backup fuels such as natural gas. The assessment concluded that the costs associated with the use of spare absorber modules or the firing of very low sulfur fuels were of the same order of magnitude. Thus, either the use of spare absorber modules or the firing of very low sulfur fuels could be used in the cost analyses to represent the additional costs of reducing emissions during periods of emission control system malfunctions. For convenience and ease of calculation, the cost analyses reflected the firing of natural gas to reduce SO₂ emissions during periods of emission control system malfunction. The capital and annualized costs of spare equipment to fire

very low sulfur fuels, such as valves, atomizers, controls, etc., were also added to the control costs. Consequently, the cost analyses considered the increased costs necessary to address reliability problems.

- E. The coal prices used in the cost analyses related to this rulemaking were developed specifically for industrial-commercial-institutional steam generating units. The coal transportation costs assumed single coal car rates to reflect the lack of volume discounts such as those obtainable by utilities, which use much greater quantities of fuel.
- F. As discussed above, the cost data used in developing the cost algorithms were developed from data submitted by vendors, and were confirmed by comparison with costs associated with actual installations. The cost algorithms, therefore, reflect the charges made for vendor services and products and thus include vendors' profit margins.
- G. The baseline used in the national impacts analysis reflects existing SIP emission limits within each AQCR as discussed earlier. The baseline used in the "model boiler" cost analysis was chosen to represent a typical, although somewhat lenient, SIP emission limit. Other baselines could have been selected. However, if more stringent baselines were used, the annualized costs for SO₂ control at the baseline would also have to be increased to account for the additional compliance costs associated with more stringent regulations. Selection of different baselines would also change the "average" cost effectiveness of various regulatory alternatives

since "average" cost effectiveness compares the costs and emissions under the alternative in question to the costs and emissions under the baseline. Of much greater significance, however, are comparisons of the incremental impacts among alternatives. Varying assumptions regarding the baseline have no effect on these comparisons and, as a result, would not change any of the comparisons of incremental impacts among alternatives, including comparisons of incremental cost effectiveness.

2. Comment: Several commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-84, IV-F-1.15) felt that the ± 30 percent accuracy of the cost estimates significantly affected the range of cost effectiveness values cited in the proposal preamble.

Response: Depending on how one views the cited cost effectiveness figures, the commenter is correct. The accuracy of the cost estimates can significantly affect the range of cost effectiveness values. In terms of individual steam generating units, the cost effectiveness figures cited could be considered as a range of expected values within ± 30 percent of the stated value. In terms of industrial steam generating units as a group, however, it is appropriate to focus on the cost effectiveness figures cited. Within a group of similar steam generating units, the subtle differences between units that give rise to the ± 30 percent accuracy range ascribed to the cost algorithms will tend to average out. As a result, the average costs are more likely to be much closer to the median or midpoint estimates provided by the cost algorithms than to either extreme of the ± 30 percent range. Thus, in terms of groups

of industrial steam generating units, the $\pm$ 30 percent accuracy ascribed to the cost algorithms has little impact on the cited cost effectiveness figures and is considered appropriate for assessing the impacts associated with regulatory actions.

3. Comment: Three commenters (IV-D-29, IV-F-1.9, IV-F-1.17) said that a percent reduction requirement would increase the maintenance, operating, and energy costs while reducing the reliability of the total production unit.

Response: Any emission standard will increase the costs for a production unit to some extent. The impacts associated with these increased costs were considered and included in the analyses of various alternatives. Similarly, the impact on reliability was also considered. Experience with industrial steam generating unit FGD systems shows them to be highly reliable technologies if they are properly operated and maintained. More important, however, the reliability of the FGD system does not affect the reliability of the steam generating unit or of the production units. Alternative fuels such as natural gas or very low sulfur oil can be employed to maintain steam generating unit operation and production at a reasonable cost during those times when an FGD system is shut down for maintenance or repair.

4. Comment: Three commenters (IV-D-55, IV-D-56, IV-D-70) said that all memoranda associated with the determination of the cost effectiveness of the standard and concerning the determination of a "reasonable" level of cost effectiveness should be identified and placed in the docket for this rulemaking for public review and comment.

Response: The notice of proposed rulemaking and materials already in the docket gave the public full notice of, and opportunity to comment on, the facts and arguments relevant to the consideration of cost effectiveness in this rulemaking. The specific memoranda referred to by the commenters are related to other regulations and proceedings and are not part of this rulemaking. Therefore, they need not be placed in the docket [See Clean Air Act Section 307(d)(3)(C), Section 307(d)(4)(B)(i), and Section 307(d)(6)(C)]. In any case, the memoranda are exempt from disclosure under the deliberative process privilege of the Freedom of Information Act, 5 U.S.C. 552(b)(5).

5. Comment: Three commenters (IV-D-31, IV-D-51, IV-D-88) asserted that in most situations, the NSPS would require investment in FGD systems for backup oil firing on gas-fired steam generating units due to the interruptible nature of natural gas pipeline supplies (especially during the heating season). Therefore, the commenters said, this should be reflected in the cost of using natural gas for compliance.

Response: Natural gas would only be unavailable in situations where the steam generating unit operator purchases an interruptible gas supply contract. Non-interruptible gas supply contracts may be purchased in many locations. The costs associated with firing natural gas assumed that noninterruptible gas supplies were purchased. If a steam generating unit operator elected to use an interruptible gas supply, the most likely and least expensive backup system would be to maintain a supply of very low sulfur oil capable of meeting an emission limit of 129 ng/J (0.3 lb/million Btu) heat input. Under the final standards, an FGD system

to reduce SO₂ emissions when firing oil would not be required as long as a very low sulfur oil was fired.

6. Comment: One commenter (IV-D-12) felt that the costs associated with the standards are too high for a modified steam generating unit. For example, the commenter said that a simple capacity expansion involving a minimal increase in air emissions would require the retrofit of an FGD system, which often would far exceed the original modification cost.

Response: As discussed previously (see Section 2.2), no general types of modifications to industrial steam generating units have been identified for which compliance with the standards is considered unreasonable. To be considered a modification, there must be an increase in the emission rate beyond the original design limits and there are ways to prevent emission rate increases, such as firing a lower sulfur fuel, to avoid invoking the modification provisions.

7. Comment: One commenter (IV-F-1.9) said industrial steam generating unit operators are faced with the probability of two separate regulatory programs that will impose stringent and costly emission controls (acid rain legislation and the proposed NSPS). According to the commenter, the costs will be approximately 5 times greater than the cost of reducing the same emissions in large steam generating units to control only a small percentage (1.5 percent) of total U.S. SO₂ emissions.

Response: To address the concern that the relative costs of emission control are much greater for industrial-commercial-institutional steam generating units than for utility steam

generating units, the relative cost effectiveness of SO₂ control for industrial and utility steam generating units was assessed. The average cost effectiveness of comparable SO₂ control, using the same assumptions for both industrial and utility units, are similar for both types of steam generating units. Therefore, there is no reason to assume that the cost of reducing a given amount of SO₂ emissions would be substantially greater for industrial-commercial-institutional steam generating units than for utility steam generating units.

Although industrial-commercial-institutional steam generating units emit less SO₂ than their utility counterparts, these emissions are still considered significant and, therefore, are subject to regulation under Section 111 of the Clean Air Act.

8. Comment: One commenter (IV-D-4) expressed the opinion that there can be no total calculation of the ultimate cost of this regulation because it has so many ramifications in so many areas. The commenter said any cost estimates will be at least 2-10 fold off the mark because all cross-media costs are never included.

Response: While it may be impossible to assess all possible costs associated with any regulation, the analysis supporting the standards attempted to address all costs. Cross-media costs, such as waste disposal and other associated environmental costs, for example, were considered. Based on a thorough examination of all of these factors, the costs associated with the final standards are considered reasonable.

9. Comment: Two commenters (IV-D-81, IV-F-1.1) said the proposal did not state what cost effectiveness figure was used to conclude that all of the substantive requirements of the proposed standard are reasonable.

Response: Although cost effectiveness is an important factor in determining the "reasonableness" of an NSPS, it is not the only factor that is considered. The Clean Air Act states that the selection of a standard must be based on the "best demonstrated technology," taking into account cost, nonair quality health and environmental impacts and energy requirements. All these things were considered in determining that the requirements of the final standards are reasonable, and were addressed in the "Summary of Regulatory Analysis" and elsewhere in the docket for this rulemaking.

10. Comment: One commenter (IV-D-44) said the costs associated with purchasing low sulfur coal were overestimated in the proposal. For example, the commenter said, one long-term coal contract allows the purchase of 0.85 percent sulfur coal for \$2.08/million Btu versus the proposal estimate of \$3.32/million Btu.

Response: As discussed elsewhere in this document, new fuel price estimates have been made since the proposal of the standards. The coal prices in these new forecasts are generally lower than those used in the proposal, and the difference in price between high and low sulfur coal (i.e., the "sulfur premium") is less than previously estimated. Therefore, the new coal prices associated with low sulfur coal have been amended to reflect these new estimates. It should be noted, however, that the fuel prices used in the cost and national impacts analyses reflect average costs

that might be incurred by a typical steam generating unit firing that fuel in the region being analyzed. The actual prices for a particular steam generating unit may be higher or lower than these average prices depending on site-specific factors.

11. Comment: One commenter (IV-D-45) said the high costs associated with tracking the desulfurization of oil, combined with the high desulfurization costs themselves, will make "compliance fuel" very expensive. The commenter felt this should be recognized in the costs of the regulation.

Response: The provisions in the proposed regulation pertaining to tracking the desulfurization of oil apply only to those facilities wishing to use credit for fuel pretreatment toward the percent reduction requirement. The use of compliance fuel as mentioned by the commenter referred to the provision in the proposal stating that facilities with potential SO₂ emissions of 86 ng/J (0.2 lb/million Btu) or less would be deemed to comply with the percent reduction requirement. This was not a compliance fuel provision, but merely an alternative means of demonstrating compliance with the 90 percent reduction requirement. As discussed previously, a reassessment of this issue indicated that there is no point at which the sulfur content of an oil is so low that one can determine with a reasonable degree of confidence that it has undergone a 90 percent reduction in its sulfur content. Therefore, this provision has been dropped in the final standards. In the final standards, a compliance fuel alternative exists for steam generating units operating at low capacity utilization rates for oil or coal and for units firing very low sulfur oil. No fuel tracking is required for steam generating units subject to these alternative requirements.

2.7.2 Control Technology Costs

1. Comment: Many commenters felt that the cost estimates associated with flue gas desulfurization (FGD) were too low. Several (IV-D-6, IV-D-28, IV-D-40, IV-D-50, IV-D-52) said that while they appear to agree well with results obtained from an independent survey, the FGD systems surveyed were dry scrubbing systems whereas the cost estimates were based on wet scrubbing. According to the commenters, studies of utility FGD systems have shown that annualized costs for dry FGD systems are usually about 10 to 30 percent less than for wet FGD systems. Therefore, they said, the estimates for wet FGD systems should be proportionately higher.

Other commenters (IV-D-10, IV-D-26, IV-D-27, IV-D-30, IV-D-35, IV-D-36, IV-D-38, IV-D-48, IV-D-50, IV-D-52, IV-D-73, IV-D-96, IV-F-1.12) said that the costs to install FGD systems on industrial-commercial-institutional steam generating units are considerably greater than for large utility units due to lack of economies of scale and will greatly increase total steam generating unit costs with little or no air quality benefit. For instance, the commenters stated that a dry FGD system would add about 17 percent to the cost of a new steam generating unit, while wet FGD systems would add 25 to 33 percent. The commenters asserted that no explanation was given as to why these higher costs are justified.

Other commenters (IV-D-5, IV-D-58, IV-D-62, IV-D-65, IV-D-66, IV-D-74, IV-D-84) stated that because sodium once-through FGD was selected as the basis for the national cost impact analysis, the costs were underestimated. The commenters said that many steam generating unit operators will select other methods, such as dual alkali or lime spray drying, for operational or waste disposal reasons. According to the commenters, capital costs for sodium throwaway systems are roughly 40 percent less than for lime spray dryers and 60 percent less than for dual alkali systems, and total annualized costs are likewise lower. The commenters felt that this "real world" variability should be taken into account in the NSPS analysis.

Response: As mentioned by a number of commenters, the economics of FGD systems are different for utility and industrial steam generating units. Because of their much larger size and the continuous nature of utility operation, operating costs play a more dominant role in the economics of FGD systems for utility units than they do for industrial units. Thus, the least expensive FGD system for a utility steam generating unit is frequently one which minimizes operating costs, often at the expense of higher capital costs. In contrast, the least expensive FGD system for an industrial steam generating unit is frequently one which minimizes capital costs, often at the expense of higher operating costs. Sodium FGD systems are characterized by relatively low capital costs, but relatively high operating costs due to the use of soda ash as a reagent. Lime spray drying systems, on the other hand, are characterized by relatively high capital costs, but relatively low operating costs due to the use of lime as a reagent. As one might expect, therefore, when the economics of these two FGD systems are

compared, lime spray drying is less expensive for utility steam generating units, but sodium scrubbing is less expensive for many industrial steam generating units.

Sodium scrubbing is currently the most widely used FGD technology for controlling SO_2 emissions from industrial steam generating units. In addition, sodium scrubbing is generally less expensive than other FGD technologies for industrial units. Consequently, the sodium scrubbing cost algorithm was used in the analyses prior to proposal of standards to generate costs which were viewed as representative of the type of FGD system that would be most widely used to control SO_2 emissions from new industrial-commercial-institutional steam generating units.

In response to comments concerning the use of the sodium scrubbing cost algorithm in this manner, however, the costs of various FGD systems were reviewed and compared again. The costs of sodium scrubbing were generally found to be somewhat lower than the costs of other FGD systems, such as dual alkali and lime spray drying, as well as fluidized bed combustion. From the standpoint of overall project economics, the total annualized cost of the steam generating unit and SO_2 control system varied by less than 10 percent for all technologies examined. However, when only the cost associated with SO_2 control was considered, this variation was much larger, ranging from 30 to 100 percent. Therefore, because of variations in project-specific factors that could influence the choice of SO_2 control system, the use of any single technology as a surrogate for all SO_2 control systems in subsequent cost analyses was judged to be inappropriate. Consequently, to avoid underestimating costs, generic cost estimates representing the mid-point in the range of cost

estimates for all types of industrial FGD systems (i.e., sodium scrubbing, lime spray drying, and dual alkali) were used to represent the costs of industrial-commercial-institutional steam generating unit FGD systems in subsequent analyses. While this resulted in somewhat higher cost estimates than at proposal, it did not lead to any significant differences in conclusions.

2. Comment: Several commenters said the operation and maintenance (O&M) costs associated with flue gas desulfurization were underestimated:
- A. Some (IV-D-12, IV-D-58, IV-D-66, IV-D-74, IV-D-84) felt that the O&M costs used in the cost analysis were not adequately documented, and that there is considerable uncertainty associated with the estimated O&M costs. The commenters requested that additional data on this point be produced and made public.
 - B. Four commenters (IV-D-10, IV-D-23, IV-F-1.15, IV-F-1.16) said the analysis did not consider the additional chemical or reagent costs required to achieve high percentage reductions and minimize the effect of load swings on FGD performance. Such costs, the commenters said, will add significantly to total operating costs.
 - C. Two of these commenters (IV-D-10, IV-D-23) also said that the increased costs of liquid and solid waste disposal at higher percent reduction requirements were not considered.
 - D. Several commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-51, IV-D-53, IV-D-88, IV-F-1.15) said that the effects of other regulations on FGD system operation and cost should be considered. The commenters specifically mentioned that FGD system cost calculations should account for the larger equipment that will be needed to

meet the NO_x standards through the use of staged combustion air, as well as the fact that stack gas reheat could be required to avoid violations of ambient standards or PSD increments.

- Response: A. The development of O&M costs is fully discussed and documented in the background information documents included with the proposed standard. A discussion of this development can be found in the "Industrial Boiler SO₂ Cost Report" and in a memorandum entitled "Sodium Scrubbing Cost Algorithm Development." In addition to the "SO₂ Technology Update Report" and "Fossil Fuel-Fired Boilers: Background Information," the basis for many of the assumptions used in developing these costs was the "Technology Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization." There are also other reports and memoranda available for review in the docket which discuss various scrubbing systems. Finally, various changes and revisions of the cost algorithms are summarized in "Summary of Revisions to the FGD Control Cost Algorithms Since 1982."
- B. The chemical and reagent costs used to assess the total annualized cost impacts of the standard were based on an average SO₂ removal efficiency of 92 percent on both high (3.54 wt. percent) and low (0.6 wt. percent) sulfur coal. In addition, chemical and reagent costs were also calculated for lower percent reduction requirements, such as 50 and 70 percent. In terms of total annualized costs, the incremental cost effectiveness of a 90 percent reduction in SO₂ emissions over lower percent reduction requirements was found to be very reasonable. This was discussed in "Summary of Regulatory Analysis."

The additional reagent costs associated with maintaining a high percentage reduction in SO_2 emissions during periods of load swings were included in the cost algorithms. These algorithms were developed based on actual operating information provided by steam generating unit users and vendors. Therefore, the cost data encompassed a wide variety of actual industrial operating conditions, including periodic load swings. While an individual plant could experience more severe or frequent load swing episodes than those included in the analysis, the cost estimates are based on conditions found at a "typical" industrial plant and are considered to be representative of FGD costs in general.

- C. The waste disposal costs included in the cost algorithms were based on an average SO_2 removal efficiency of 92 percent. Therefore, the costs associated with waste disposal at higher percent reduction requirements were considered in the analyses, and these costs are considered representative of typical disposal costs.
- D. The "baseline" for analysis of various standards limiting SO_2 emissions from new industrial-commercial-institutional steam generating units represents compliance with existing SIP requirements as well as compliance with the final NSPS limiting particulate matter and nitrogen oxides (NO_x) emissions from new industrial-commercial-institutional steam generating units. As a result, the costs to comply with ambient SO_2 standards were included in baseline costs. Similarly, costs for NO_x control (the use of low excess air and staged combustion air) were included in the baseline costs.

In addition, the analysis of secondary environmental impacts also examined the potential impact on ambient air SO₂ concentrations of various standards limiting SO₂ emissions. The analysis indicated that none of the ambient air quality standards or the limits on deterioration of air quality, such as those under the PSD program, were exceeded. Consequently, no additional requirements to comply with ambient SO₂ standards or PSD requirements were identified.

3. Comment: Some commenters mentioned site-specific differences in costs that could be encountered. Several (IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-84) said that the use of multiple package FGD systems to represent a single large system is inaccurate, because many large steam generating unit owners will be forced to use a single field-erected unit due to space limitations.

Another commenter (IV-D-21) expressed the opinion that the cost analysis did not give adequate consideration to the space required for a dry FGD system. The commenter said the space needed for the actual control equipment, the water treatment equipment, and for waste disposal would be especially critical for steam generating units in an urban area.

Response: Standards of performance are based on an analysis of impacts associated with various regulatory alternatives. This analysis focuses primarily on cases or scenarios which are considered representative of the types of situations and constraints individuals might generally face. In this respect, as discussed earlier, the cost analysis did consider the costs associated with additional space

requirements for emission control equipment, the costs of waste disposal, and the type of steam generating unit installed (i.e., package or field erected). In addition, the analysis also examined cases or scenarios representative of specific situations where special provisions may be appropriate. Thus, the analysis also examined, for example, impacts on small as well as large steam generating units, units operating at low capacity factors as well as high capacity factors, units firing low sulfur as well as high sulfur fuels, cogeneration systems as well as conventional steam generating units, units located in the western United States as well as those located in the eastern United States, and steam generating units in specific industries likely to be most affected by standards.

In some cases, especially where space limitations restrict the SO₂ control equipment, a steam generating unit operator will elect to install a single, large, field-erected FGD system rather than the smaller multiple package units assumed for purposes of analysis. However, this should not significantly affect the costs associated with most steam generating units in the size range covered by the NSPS. Although equipment costs for the shop-fabricated (package) approach are higher than those for larger field-erected systems, the total installation costs (material plus labor) are lower. Therefore, the underestimation of installation costs for field erection will be largely offset by the overestimation of equipment costs. Review of the analysis also indicates that where the costs of FGD become excessive, these costs can be avoided by firing an alternative fuel, such as natural gas. The impacts of such fuel switching were evaluated and are considered reasonable. Thus, no

special provisions for site-specific factors were judged to be appropriate.

4. Comment: Two commenters addressed the impact of the capital costs of FGD systems on oil-fired steam generating units. One (IV-D-79) said the regulatory impacts analysis is significantly understated and does not adequately address the cost impact of the NSPS on the petroleum industry. Specifically, the commenter said, forecasts that the capital cost of a typical industrial steam generating unit would increase by 4 to 25 percent under the proposed standard were incorrect. The commenter's experience indicates that the capital cost increase for a 73 MW (250 million Btu/hour) unit would be 89 percent. The other commenter (IV-D-12) also said that the capital costs of a new oil-fired steam generating unit would be increased by 30-100 percent as a result of the proposed rule. According to the commenter, this will be amplified by the added costs to operate the FGD system and dispose of the sludge.

Response: The capital costs associated with installing FGD systems on oil-fired steam generating units were assessed and discussed in the "SO₂ Cost Report." This report discusses the specific cost assumptions and methodologies used in calculating the capital costs for both the uncontrolled steam generating unit and the SO₂ control device. For a 73 MW (250 million Btu/hour) heat input capacity steam generating unit in Region V, the capital cost for an uncontrolled oil-fired steam generating unit was \$4,579,000, compared to \$5,500,000 for a steam generating unit equipped with an FGD system (including waste handling equipment). This represents only a 20 percent increase in capital cost, rather than the 30 to 100 percent figures cited by the

commenters. It is possible that steam generating unit operators could experience costs that are higher or lower than this depending on site-specific factors, but the capital cost estimates in the "SO₂ Cost Report" are considered representative of typical steam generating unit costs.

5. Comment: Two commenters felt that the capital costs of FGD systems for coal-fired steam generating units were too high. One (IV-D-87) felt that, based on capital costs for FGD systems alone, smaller entities cannot afford the SO₂ controls for coal and residual oil-fired steam generating units. The commenter said the cost of a new 44 MW (150 million Btu/hour) unit with a baghouse and spray dryer for SO₂ control (or conversion to fluidized bed combustion) is approximately \$6 million. Another (IV-F-1.18) contended that a requirement for FGD systems will increase project capital costs by at least \$1 million and will not result in sufficient operating cost savings to justify the investment. As a result, the commenter said, few industrial coal-fired units will be built in the future.

Response: The capital costs associated with installing FGD systems on coal-fired steam generating units were discussed in the "SO₂ Cost Report." As discussed above for oil-fired units, the assumptions used in calculating these costs for both the uncontrolled steam generating unit and the SO₂ control device were detailed in this report. For a 44 MW (150 million Btu/hour) heat input capacity steam generating unit in Region V, the capital cost for an uncontrolled bituminous coal-fired steam generating unit was \$14,050,000, compared to \$14,899,000 for this same steam generating unit equipped with a sodium FGD system. This represents an

increase of about \$850,000, or 6 percent of the capital cost. The capital cost of a lime spray drying system, while higher than that associated with sodium scrubbing, would add only about 10 percent to the uncontrolled steam generating unit costs. Therefore, the costs associated with the steam generating unit itself will likely play a far more important role in determining affordability than the cost of the SO₂ control system.

Data from the previously discussed boiler replacement survey indicate that of the 89 projects surveyed, only 7 projects (8 percent) would have been changed if project costs increased by 10 percent. These data indicate that while some steam generating unit projects may be altered based on the results of the survey, most projects would have been built as planned.

6. Comment: One commenter (IV-D-42) said the cost impacts of adding an FGD system to a municipal resource recovery incinerator which fires oil as a startup fuel only were much higher than those cited in the proposal. Specifically, the commenter said the annualized costs of a dry FGD system when examined over a 20-year period could add 25 to 45 percent to the operating cost of a municipal resource recovery incinerator when considering all cost factors, including the loss in revenue because of a decrease in net electric generation. The commenter noted that this is considerably higher than the 6 to 22 percent increase projected at proposal.

Response: In the final standard, a municipal resource recovery incinerator firing a very low sulfur oil would not be subject to the percent reduction requirement.

7. Comment: One commenter (IV-F-1.19) discussed the viability of steam generating unit installations under various alternatives. The commenter said that at one recent installation, the payback period was 3.5 years for low sulfur coal, 4.2 years for a dry scrubber, and 4.3 years for a wet scrubber. According to the commenter, this small range was enough to cause the steam generating unit not to be built if scrubbers were required. At another installation, the payback period was 2.5 years for low sulfur coal, versus 3.1 years for a dry scrubber and 3.3 years for a wet scrubber. Again, the commenter said, with a scrubber requirement, the project would not have been built.

Response: The economics of installing a steam generating unit, with or without an FGD system, will vary from site to site. As evidenced by the commenter's example, a payback period of 3.5 years may be acceptable for one facility, whereas a payback period of 3.3 years may be unacceptable for another. In developing national standards of performance, it is not possible to predict impacts on a site-specific basis. The impacts of the standards have been determined to be reasonable on a national basis, as well as for individual industrial-commercial-institutional steam generating units in general. If the costs associated with installing and operating an SO₂ control system would prove to be too high for a particular steam generating unit, the steam generating unit operator could elect to fire natural gas or very low sulfur oil in order to avoid the costs of SO₂ control.

8. Comment: One commenter (IV-D-48) said the cost per ton of SO₂ removed under a percent reduction requirement is higher for low sulfur coals than for high sulfur coals due to the smaller

amounts of sulfur present. The commenter contended that it makes no sense to penalize sources using lower sulfur fuels by not providing a "sliding scale" percent reduction requirement.

Response: The commenter is correct in saying that the cost per ton of SO₂ removed could be higher for low sulfur coals. However, this does not "penalize" sources using low sulfur fuels. Of more concern to the steam generating unit operator is the total annualized cost associated with SO₂ control. Total annualized costs actually can be lower for lower sulfur coals due to the reduced operational and waste disposal costs associated with lower sulfur coal. Analyses of a sliding scale standard analogous to Subpart Da for industrial-commercial-institutional steam generating units found that the additional cost of 90 percent SO₂ removal was reasonable relative to the sliding scale.

9. Comment: Two commenters (IV-D-45, IV-D-76) said the proposal states that the percent reduction standard is not significantly more costly than a low sulfur fuel standard. However, by the proposal's estimates, the national annualized cost associated with a standard based on percent reduction is \$133 million, compared to \$57 million for a standard based on the use of low sulfur fuel. The commenters noted that this is an increase of more than 130 percent.

One (IV-D-76) added that the national cost effectiveness calculation, which projects "average" national incremental removal costs of \$940/Mg (\$850/ton) over a low sulfur fuel standard, underestimates the cost of a scrubber-based percent reduction requirement for steam generating units using coal or oil due to the fuel switching assumption.

According to the commenter, this number is well below the costs that could be incurred by individual owners and operators not switching to natural gas, which could range as high as \$4,400/Mg (\$4,000/ton). Also, the commenter said, some steam generating unit classes operating at lower capacity factors incur control costs that are comparable to the \$1,760 Mg (\$1,600/ton) that was considered "unreasonable" for mixed fuel units. Another commenter (IV-D-96) agreed, saying that the implications of the fuel switching assumption on whether the standard would have unreasonable impacts were not properly considered.

Response: The national impacts associated with the standard were reassessed using the Industrial Fuel Choice Analysis Model [i.e., IFCAM) and revised fuel price projections (see "Revised Impacts of Alternative Sulfur Dioxide New Source Performance Standards for Industrial Fossil Fuel-Fired Boilers"). The new analysis projects that even in the absence of an NSPS, no new coal-fired steam generating units would be built due to the capital-intensive nature of these units and the relatively small price differential among coal, oil, and natural gas. In addition, the prices of natural gas and oil appear to be so competitive that even an NSPS establishing an emission limit only (i.e., without a percent reduction requirement) causes almost all industrial-commercial-institutional steam generating units to fire natural gas. Thus, the analysis of national impacts projects little or no difference at the national level between the costs associated with firing low sulfur fuels and those associated with achieving a percent reduction in SO₂ emissions. Either alternative would be expected to result in total nationwide annualized costs of \$5 million (assuming high oil prices) to \$50 million/year (assuming low

oil prices). Because of the similarity in cost estimates under both regulatory options, the incremental cost effectiveness of a percent reduction standard compared to a low sulfur coal standard is projected to be negligible. An alternate analytical approach developed to estimate national impacts under the assumptions that many industrial-commercial-institutional steam generating units will be coal fired and that fuel switching does not occur was also used. The national cost estimates under these assumptions are \$23 million for a low sulfur fuel standard and \$124 million for a percent reduction standard. The estimated incremental cost effectiveness of a percent reduction standard under these assumptions is \$1,600/Mg (\$1,400/ton). These costs are considered reasonable considering the significant emission reductions achieved by a percent reduction requirement.

It is possible that individual steam generating unit operators could incur costs that are significantly higher (or lower) than the national average cost effectiveness values. In particular, the costs associated with achieving a percent reduction in SO_2 emissions could be unreasonably high for steam generating units that receive only a small amount of their total heat input from coal or oil, or those that operate at only a small portion of their total annual capacity. For this reason, in the final standard, steam generating units operating at an annual capacity utilization factor for coal or oil, or a mixture of coal and oil, of less than 30 percent are not subject to a percent reduction requirement, but need meet only an emission limit.

2.7.3 Waste Disposal Costs

1. Comment: Several commenters (IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-84) said that waste disposal costs will greatly increase if FGD system sludge is designated a hazardous waste subject to disposal requirements under the Resource Conservation and Recovery Act (RCRA). They felt this had not been considered in developing the standards.

Response: Sludge generated by FGD systems is not currently considered a hazardous waste under RCRA and, thus, it would be inappropriate to consider it as such in the analysis. If this should happen, however, it could alter the relative economics of various SO₂ control systems, making the costs of those systems producing larger volumes of wastes or wastes with certain undesirable characteristics higher than the costs for other types of systems. Thus, such a decision could alter the choice of SO₂ control system. In addition, if the costs increased to the point where they were regarded as excessive in certain cases or at specific sites, then such a decision could alter the selection of fuel for the steam generating unit. In such situations, use of very low sulfur fuels, such as natural gas, would avoid these waste disposal costs. As mentioned earlier, the impacts associated with such fuel switching are considered reasonable. Thus, regardless of whether FGD or FBC system waste is designated a hazardous waste under RCRA, the impacts associated with the standards are considered reasonable.

2. Comment: One commenter (IV-D-44) asserted that the ash disposal costs associated with the standards were greatly underestimated. The commenter said that without even considering the extreme

costs of disposal in lined landfills, ash disposal costs alone are \$12/ton in Michigan, \$45/ton in New Jersey, and \$25/ton in Virginia.

Response: Ash handling and disposal systems and their associated costs were included in the cost algorithms as part of the uncontrolled steam generating unit (i.e., "baseline") costs. The costs of ash disposal, however, do not arise as a result of compliance with SO₂ control requirements under standards of performance. The need for ash disposal results from burning the fuel itself, not from controlling SO₂ emissions. Thus, these costs have little bearing on considerations regarding selection of standards limiting SO₂ emissions.

3. Comment: One commenter (IV-D-48) said that the costs for industries which dispose of their own wastes were not considered. According to the commenter, these costs should include capital costs relating to landfill construction, monitoring costs, site closure costs, oxidation equipment and operating costs, and permit application and monitoring costs.

Response: The cost algorithms assume that most steam generating unit operators would elect to dispose of their wastes off-site rather than invest in waste treatment and disposal systems. The waste disposal costs used in the algorithms reflect the typical costs of off-site disposal. The costs associated with on-site disposal, for industries which dispose of their own wastes, could be higher or lower than the off-site costs assumed by the cost algorithms, depending on site-specific situations or local requirements. If on-site disposal costs are lower, the cost algorithms will overestimate costs. If on-site disposal costs are higher, operators will likely select off-site disposal and the cost

algorithms will more accurately reflect costs. Thus, the assumption of off-site disposal is a "conservative" assumption which, if anything, is more likely to overestimate costs in cases of on-site disposal.

4. Comment: Several commenters felt that sodium FGD system wastewater treatment costs were underestimated. Some (IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-D-73, IV-F-1.15) said that sodium scrubber wastewater treatment costs such as ion exchange or reverse osmosis technology could be incurred at some facilities and should be considered. According to the commenters, these costs can be significant (\$200,000-\$500,000).

One commenter (IV-F-1.15) said that the estimate of total costs for oxidation of the sodium FGD system waste stream (\$60,000) was low by a factor of 2 to 3, assuming discharge to a publicly owned treatment works (POTW).

Response: The cost associated with sodium FGD wastewater treatment and disposal was represented in the analyses by oxidation of the wastewater stream and discharge to a receiving water body or POTW. These costs were discussed in "SO₂ Re-emissions from the Sodium Scrubbing Wastewater Stream in Aerobic Environments." While total direct costs for a wastewater stream with a small sulfite loading were estimated at \$60,000, the total turnkey costs associated with installing an oxidation tower ranged from approximately \$95,000 for a small wastewater stream to \$430,000 for a large wastewater stream. These costs were based on actual vendor data and are considered to be accurate within the range of accuracy of the cost estimates in general. Costs for other wastewater treatment techniques, such as ion exchange or

reverse osmosis technology, were not considered in the analysis. Although these costs could be incurred at some facilities depending on site-specific disposal requirements, they are not considered representative of "typical" costs that would be incurred at most facilities. If the costs increased to the point where they were regarded as excessive by the steam generating unit operator, an alternative FGD system, such as lime spray drying, could be used to change the nature of the waste or, alternatively, a very low sulfur fuel such as natural gas could be fired in the steam generating unit to avoid these costs.

2.7.4 Startup, Shutdown, and Malfunction Costs

1. Comment: Many commenters (IV-D-6, IV-D-22, IV-D-26, IV-D-28, IV-D-30, IV-D-32, IV-D-40, IV-D-44, IV-D-50, IV-D-51, IV-D-52, IV-D-53, IV-D-58, IV-D-61, IV-D-62, IV-D-65, IV-D-66, IV-D-73, IV-D-74, IV-D-84, IV-D-88, IV-F-1.6, IV-F-1.16) expressed concern that the capital costs of auxiliary fuel systems necessary for startups, shutdowns, and upsets were not considered. Commenters specifically mentioned costs for burners, piping, storage, and other equipment, and said that these costs are significant. In addition, commenters noted that if very low sulfur oil is used as the backup fuel, the costs for low-NO_x burners should be included to achieve the NO_x limits. According to the commenters, typical costs for providing low sulfur oil backup capability could be \$300,000-\$500,000.

Response: Many steam generating units are already designed and constructed with alternative fuel firing capability to allow greater flexibility in fuel selection and to provide for steam generating unit startup capability. In these cases,

the only additional costs for firing natural gas or very low sulfur oil during periods of startup, shutdown, and malfunction would be the difference in the price between natural gas or very low sulfur oil and coal. However, because not all boilers have this capability, additional capital costs were included in the cost analysis to provide the flexibility of switching from firing coal or oil to firing natural gas or very low sulfur oil during periods of malfunction. For example, in the case of switching from coal to a very low sulfur oil, additional costs were included for oil guns, piping, flow control valves, burner control system, fuel oil heaters, pumps, oil storage tanks, additional draft control, coal shutoff gates, cinder reinjection cutoff gates, and, in the case of stoker coal steam generating units, thermocouples on the stoker gate. For all model steam generating unit sizes analyzed (100, 150, 250 and 400 million Btu/hour), the capital cost of providing alternative fuel firing capacity to a coal-fired steam generating unit was about two to three percent of the total steam generating unit cost. The annualized cost of providing alternative fuel firing capability was three to four percent of the annualized cost of the steam generating unit system. Therefore, while the additional capital costs of providing very low sulfur fuel backup capability could be in the range suggested by the commenter, they would still represent only a very small percentage of the total steam generating unit costs while providing significant benefits in terms of additional SO₂ control.

Relative to NO_x control costs, they were fully addressed in the promulgation of the NO_x standard on November 25, 1986 (51 FR 42768). Additionally, even if they were not included in the analysis, the cost of low NO_x burners compared to

conventional burners is insignificant, and in relation to SO₂ control cost where percent reduction requirements are applicable, would not affect any conclusions related to the reasonableness of percent reduction requirements.

2. Comment: One commenter (IV-D-32) said the rationalization for a 90 percent reduction requirement seems to rely heavily on more costly backup fuels which may or may not be available. The commenter said that fuel costs appear to have been underestimated, especially considering the likelihood of frequent startup and shutdown events experienced by some individual steam generating units such as those operated only on weekdays.

Response: The impact of startup and shutdown procedures was considered, including the potential need to fire alternative fuels during these procedures. Information provided by scrubber vendors, however, indicates that the startup/shutdown time for FGD systems is minimal and that this time can be integrated in such a way with normal startup and shutdown procedures associated with the steam generating unit that periods during which the control system might need to be bypassed would be extremely brief. As a result, in most cases there should be no necessity, beyond conventional practice, for firing alternative fuels during such periods.

In most cases steam generating units subject to frequent startups and shutdowns are likely to be gas-fired, not only for ease of operation and simplicity, but also for economic reasons. Steam generating units subject to frequent startups and shutdowns are also likely to operate at low annual capacity utilization rates. Thus, as discussed

previously, such low capacity units would not be subject to a percent reduction requirement. The economics of low capacity factor steam generating units also favor the selection of alternative fuels, such as natural gas, over selection of coal. In addition, many coal-fired steam generating units normally use premium fuels such as natural gas for startup. This is done not only to bring the steam generating unit up to operating temperature, but to serve as a source of ignition for the coal. Thus, the standards are likely to have little impact on steam generating units subject to frequent startups and shutdowns.

However, in order to consider those few situations where the need to cope with frequent startups and shutdowns might impose additional costs, such as the need to fire natural gas or very low sulfur oil, the increased costs associated with those situations were examined. Assuming that a typical 44 MW (150 million Btu/hour) coal-fired steam generating unit (operating at an overall annual capacity utilization factor of 0.6) undergoes startup or shutdown about five percent of the time it is in operation, the increased costs of firing natural gas during these periods would increase the annualized cost of the steam generating unit and FGD by less than one percent. More important, however, the incremental cost effectiveness of the additional SO₂ emission control achieved would be less than \$1,100/Mg (\$1,000/ton). This is not considered unreasonable. Consequently, no special provisions are considered necessary to accommodate startup/shutdowns.

3. Comment: Two commenters (IV-D-31, IV-F-1.16) felt that higher costs should be assigned to FGD system malfunction because downtime for manufacturing firms can be very costly.

Response: The reliability of the emission control system and any FGD malfunction does not affect the reliability of the production unit. The model systems analyzed in the development of this standard were designed to include alternative fuel firing capabilities which would preclude the necessity for any downtime in the production unit as a result of FGD malfunction. By switching to an alternative fuel, such as natural gas, the production unit would be able to continue operations with essentially no interruptions. Outside of FGD system malfunction, routine inspection and maintenance of the FGD system could be scheduled for periods when the steam generating unit and/or the production units are also shut down for routine inspection and maintenance, thus avoiding any impact on the operation of production units.

2.7.5 Monitoring, Recordkeeping, and Reporting Costs

1. Comment: One commenter (IV-D-28) said the assumption that steam generating units using low sulfur fuels still be required to perform continuous emission monitoring results in monitoring costs that exceed pollution control costs in some cases. The commenter suggested that provisions for alternative monitoring or sampling procedures such as those in the current NSPS would markedly improve the cost effectiveness of compliance fuels and coal cleaning technologies, while not affecting the cost effectiveness of FGD.

Response: Under the final standards, alternative monitoring procedures are available in those cases an owner or operator judges continuous emission monitoring system (CEMS) costs to be unreasonable. Fuel sampling and analysis at the inlet to the SO₂ control device can be used in lieu of a CEMS, and

Method 6B stack sampling (see 40 CFR Part 60, Appendix A, Method 19) can be used in lieu of an outlet CEMS for those facilities where percent reduction requirements are applicable. For steam generating units operating with annual capacity utilization factors for coal or oil of less than 30 percent or firing very low sulfur oils, any one of three monitoring methods may be used: inlet fuel sampling, outlet CEMS, or stack sampling using Method 6B. Only a single monitoring alternative is necessary for these units. In addition, the NSPS General Provisions in 40 CFR 60.13(i) provide for alternative monitoring procedures, subject to approval by the Administrator, under various conditions. Therefore, if monitoring costs would be excessive in certain circumstances, alternatives are available to reduce these costs.

2. Comment: Several commenters (IV-D-26, IV-D-30, IV-D-32, IV-D-50, IV-D-53) said that costs for backup monitoring equipment, backup data processors, and the manhours needed to comply with the monitoring, reporting, and recordkeeping requirements were not considered.

Response: The minimum data availability requirement of 22 out of 30 steam generating unit operating days was established to minimize the need for backup monitoring equipment. This level of data availability is achievable unless the equipment is not being properly operated or maintained. To account for infrequent and unusual circumstances, however, in which data may not be available, data estimation procedures have been provided in Method 19, Section 7.

Manhours associated with data collection and preparing periodic reports were calculated and considered, and a detailed breakdown of the manhours associated with the reporting and recordkeeping requirements is included in the docket for this rulemaking.

2.8 PERFORMANCE/RELIABILITY OF DEMONSTRATED TECHNOLOGIES

2.8.1 Flue Gas Desulfurization

1. Comment: Many commenters (IV-D-26, IV-D-30, IV-D-32, IV-D-40, IV-D-50, IV-D-53, IV-D-62, IV-D-65, IV-D-66, IV-D-72, IV-D-73, IV-D-74, IV-D-84, IV-D-96, IV-F-1.1, IF-F-1.8, IF-F-1.12, IV-F-1.16, IV-F-1.18) said there is inadequate proof that there are demonstrated technologies which can meet the 90 percent removal requirement on a continuous basis. They contended that the performance of "demonstrated" technologies, such as flue gas desulfurization (FGD), has largely been gathered on utility steam generating units while ignoring the totally different design and operating requirements of industrial units.

Response: The performance data for FGD systems discussed in the "Summary of Regulatory Analysis, Fossil Fuel-Fired Industrial Boilers-Background Information," and "SO₂ Technology Update Report" are based on experience with industrial steam generating units. Moreover, as also discussed, for several types of FGD systems this experience is supported by experience with utility FGD systems.

Lime and limestone FGD systems, because of higher capital and maintenance costs, have had limited application in the industrial sector. In a long-term test at an industrial steam generating unit that operated a lime/limestone FGD system, the SO₂ removal efficiency was over 91 percent for lime and 94 percent for limestone. Removal efficiencies were insensitive to changes in steam generating unit load. In addition, lime and limestone wet FGD systems are proven processes in the utility industry. Lime and limestone

FGD systems account for approximately 68 percent of the total number of utility FGD systems. Although few, if any, lime or limestone FGD systems are expected to be installed on industrial-commercial-institutional steam generating units, there are no technical limitations which would make this technology less effective on industrial steam generating units than on utility steam generating units.

The performance and reliability of lime spray drying systems and fluidized bed combustion (FBC) steam generating units have also been demonstrated in industrial applications and are discussed elsewhere in this section.

Dual alkali is the second most prevalent FGD system in use on industrial steam generating units. Tests of industrial dual alkali FGD systems have shown average SO_2 removal efficiencies of around 90 percent, with long-term efficiencies of around 92 percent. Removal efficiencies of 95 percent or greater have been achieved on a continuous basis under certain operating conditions (such as operating in a dilute mode with low TDS concentrations).

Sodium FGD systems have been the FGD system most often used on industrial steam generating units. Therefore, the industrial data base for this technology is more extensive than those for other FGD technologies. Both short- and long-term tests of sodium FGD systems on industrial steam generating units showed consistent SO_2 removal efficiencies of greater than 90 percent. Emissions data from 45 industrial FGD systems, representing 18 sites, showed an average SO_2 removal efficiency of greater than 96 percent.

Consequently, the ability of FGD systems to achieve a 90 percent reduction in SO_2 emissions is well demonstrated by the experience of a number of different FGD systems currently operating on industrial steam generating units. The experience from similar systems operating on utility steam generating units only serves to confirm and add additional support to this experience.

2. Comment: One commenter (IV-F-1.15) stated that the data presented with the proposal do not support the 90 percent SO_2 removal standard for oil-fired steam generating units and are not representative of typical industrial steam generating unit performance. Specifically, the commenter said there are no long-term test data available during oil firing, and the short-term data are heavily dependent upon Kern County oil field steam generating units. The commenter asserted that these base load units operate at constant loads, in contrast to typically widely swinging industrial steam generating unit loads, and therefore are not representative of industrial steam generating unit performance.

Response: Industrial FGD experience on oil-fired steam generating units has been generally limited to sodium FGD systems. As discussed in the " SO_2 Technology Update Report," a large portion of the sodium FGD system performance data base was gathered from oil field steam generating units which are used to enhance oil recovery. The SO_2 removal efficiency of sodium FGD systems operating on these units averaged over 95 percent. These steam generating units do operate at fairly constant load; however, data were also gathered from sodium FGD systems operating on oil-fired steam generating units in other industrial applications, including those with typically widely swinging loads. A series of short-term

compliance tests conducted on a number of sodium FGD systems operating on oil-fired steam generating units in various industrial manufacturing plants showed SO₂ removal efficiencies ranging from 89.3 to 99.4 percent and averaging 96.5 percent. Also, long-term data have shown average SO₂ removals of 95 percent at high (98 percent) reliability levels for sodium FGD systems operating on oil-fired steam generating units.

Although dual alkali FGD systems have generally not been applied on oil-fired steam generating units, they should perform just as well as sodium FGD systems. The SO₂ control loop of dual alkali FGD systems operates in basically the same manner as a sodium FGD system; thus, dual alkali FGD systems can attain SO₂ control performance levels equivalent to sodium FGD systems.

In addition, emissions from coal-fired steam generating units contain more trace metals and other elements that could adversely affect the SO₂ removal efficiency of an FGD system than emissions from oil-fired steam generating units. Therefore, FGD performance on oil-fired units should be at least as good as FGD performance on coal-fired units.

3. Comment: One commenter (IV-D-62) said that an average 90 percent reduction is feasible only when a steam generating unit is using a high sulfur fuel; it is less feasible when a low sulfur fuel is used because of the lower dilution of the pollutant to be removed.

Response: The ability of an FGD system to achieve high levels of SO₂ removal during combustion of low sulfur fuels is determined by the concentration of SO₂ in the flue gas exiting the FGD

system. Test data from sodium and lime spray drying FGD systems and from FBC systems indicate SO₂ concentrations of less than 15 ppm are achievable (in some tests, SO₂ concentrations of less than 5 ppm were measured); a concentration of 15 ppm is roughly equal to 0.025 lb SO₂/million Btu. This equates to 90 percent removal on an inlet flue gas with 0.25 lb SO₂/million Btu, or 98 percent on an inlet flue gas of 1.2 lb SO₂/million Btu. These performance levels measured in operating FGD systems are supported by kinetic data from laboratory studies and by FGD vendor claims. Consequently, the ability to achieve a 90 percent reduction when firing low sulfur fuels is considered well demonstrated.

4. Comment: Several commenters questioned the adequacy of the data presented on FGD performance. Some (IV-D-6, IV-D-26, IV-D-28, IV-D-30, IV-D-40, IV-D-50, IV-D-52, IV-D-53, IV-D-73, IV-D-96, IV-F-1.15, IV-F-1.16) stated that the analysis of FGD performance significantly underestimates the impacts on industrial steam generating unit owners of a mandatory percent reduction requirement. They claimed that variable operating modes and high capacity load swings typical of industrial operations can cause severe upsets in scrubber efficiency and reliability. Also, the commenters said, the test data in most cases did not reflect full load operations, and, therefore, did not reflect typical operating conditions.

Others (IV-D-26, IV-D-30, IV-D-50, IV-D-51, IV-D-53, IV-D-88, IV-F-1.15, IV-F-1.16) noted that the assessments of FGD performance in removing SO₂ stressed the importance of several critical variables to FGD system performance. They said, however, that the performance test data presented did

not report these variables in many cases, making it impossible to correlate emissions data with these key variables.

Response: The FGD system performance data base is primarily composed of data collected from industrial steam generating unit installations. These steam generating units were located at plants representative of the industrial-commercial-institutional steam generating unit population, including steam generating units operated under many different conditions. Steam generating units with average loads (capacity utilization factor) ranging from 5 to 100 percent were included in the data base. In addition, steam generating unit loads were varied during tests of individual units to simulate load swings that might be experienced in some industrial applications. Based on this data, SO₂ removal efficiency was found to be insensitive to changes in steam generating unit load over the ranges observed.

The primary concern for FGD systems operating on steam generating units which experience load swings is a sudden increase in the SO₂ loading. This can result from an increase in either the flue gas flow rate or the flue gas SO₂ concentration. As discussed in the "SO₂ Technology Update Report," changes in flue gas flow rate are matched by corresponding changes in the scrubbing solution flow rate according to a set liquid-to-gas (L/G) ratio. In a well designed and operated system, a safety margin is maintained in the L/G ratio to account for delays in control loop response; thus, an increase in flue gas flow rate would be adequately handled. Also, FGD systems which experience highly variable SO₂ loadings typically operate at high alkaline reagent concentrations. This provides a buffering

capacity against large swings in solution pH caused by dramatic changes in SO₂ concentration. As a result, sufficient excess alkaline reagent is present to ensure adequate SO₂ removal performance during load swings.

5. Comment: A number of commenters questioned the reliability of FGD systems. Several (IV-D-6, IV-D-26, IV-D-28, IV-D-30, IV-D-40, IV-D-50, IV-D-52, IV-D-53, IV-D-73, IV-F-1.16, IV-F-1.17) said that although the proposed regulation assumes that reliable FGD systems can be economically constructed and operated, the operational history of FGD systems does not bear this out. Two other commenters (IV-D-44, IV-F-1.19) asserted that no environmentally acceptable FGD system has been demonstrated to meet the high availabilities (around 85 percent) required by some facilities, such as cogeneration facilities. In addition, two commenters (IV-D-26, IV-D-35) expressed concern that decreased steam generating unit reliabilities due, in part, to the uncertainty of the FGD system can result in extremely high costs incurred due to process shutdowns in many plants at which continuous steam generating unit operation is required. The commenters felt that this incompatibility between FGD efficiency levels and industrial steam generation requirements has not been addressed.

Four commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53) also maintained that utility FGD operability and reliability experience cannot be extrapolated to industrial operation because most utilities install spare scrubbers to improve reliability, do not experience the radical load fluctuations typical of industrial operations, and have enough operation and maintenance personnel to keep equipment running, unlike small industrial facilities.

Response: The reliability of various types of FGD systems for industrial applications was discussed in the "Background Information Document," the "Summary of Regulatory Analysis," and the "SO₂ Technology Update Report." For lime spray drying systems, reliability levels ranging from 70 to 97 percent were reported for various test sites. Some decrease in reliability was reported with increasing SO₂ removal efficiency. However, an examination of the reasons for decreased reliability indicated that the FGD system failures were not generally the result of increased system stress, but were due to other factors unrelated to SO₂ removal efficiency and could often have been prevented with improved operating and maintenance procedures or maintaining a spare parts inventory. In fact, one vendor of lime spray dryers is prepared to offer a guarantee of 95 percent reliability providing the customer follows a preventive maintenance program. The ability of lime spray dryers to achieve high reliability levels is also supported by the history of one lime spray dryer operating on a 132 MW (450 million Btu/hour) steam generating unit in Michigan, which over 2 years (1985 and 1986) has achieved in excess of 98 percent reliability.

During a long-term (85-day) performance test of a lime/limestone FGD system on an industrial steam generating unit, FGD system reliability was greater than 90 percent (91 percent when lime was the reagent and 94 percent when limestone was the reagent). Limestone FGD systems have also demonstrated high reliabilities when applied to utility steam generating units. Data from one utility lime/limestone FGD system firing coal indicate reliabilities close to 100 percent over a period of several years.

Data for sodium FGD systems also indicate high reliabilities for industrial applications. Average reliability levels of 98-100 percent have been reported for over 250 coal- and oil-fired steam generating units for long periods of time (several months to several years in length) at high SO₂ removal levels.

The reliability of fluidized bed combustion systems is discussed in a subsequent section of this document.

The above discussion indicates, therefore, that with proper operation and maintenance, high FGD reliabilities can be achieved and maintained on industrial steam generating units operating at high SO₂ removal levels. For compliance during periods of FGD malfunction, the cost of firing alternative low sulfur fuels, such as natural gas, in the steam generating unit was included in the cost calculations. As an alternative approach, installation of backup FGD modules, common in the electric utility sector to ensure system reliability, may be used on industrial-commercial-institutional steam generating units.

6. Comment: Several commenters expressed the opinion that the performance and reliability of dry FGD systems have not been demonstrated in industrial applications. Three commenters (IV-D-44, IV-F-1.17, IV-F-1.18) said that lime spray drying systems have a dismal performance and reliability record in the few installations at which they are operating, and should not be included in the standards. Another (IV-D-48) said the 90 percent removal requirement will preclude dry FGD technologies, forcing facilities firing low sulfur coals to live with wet SO₂ removal options. Others (IV-D-26, IV-D-30, IV-D-50, IV-D-53) stated that the "Summary of

Regulatory Analysis" identifies no exceptions to the application of spray dryers to coal-fired steam generating units, while "Projected Environmental, Cost and Energy Impacts of Alternative SO₂ NSPS for Industrial Fossil Fuel-Fired Boilers" notes that lime spray drying is not a control option for medium and high sulfur coals regardless of the SO₂ removal rate. They felt that this was inconsistent with the statement that lime spray drying is a demonstrated technology.

Response: The performance and reliability of lime spray drying has been demonstrated, as discussed in the "Summary of Regulatory Analysis" and the "SO₂ Technology Update Report." The citation quoted by the commenters to the contrary is the result of an error that had been overlooked prior to publication. Although little long-term data are available to demonstrate high SO₂ removal levels, short-term tests have indicated that lime spray drying systems are capable of achieving performance levels in excess of 93 percent. The long-term average removal levels of 60 to 80 percent that have been observed to date are not indicative of an inherent inability to achieve high levels of performance over long periods of time, but rather reflect the fact that these systems have not been required to achieve such high removal levels. Therefore, owners and operators have operated them at the minimum efficiency required to save on operating costs. As discussed above, high FGD reliabilities have been demonstrated for lime spray dryers. Although most lime spray dryers today are operated at moderate performance levels, there is no reason to believe lime spray dryers could not maintain these high reliabilities with increasing SO₂ removal. Nothing in the results demonstrating the capability to achieve high performance levels of 90 percent

reduction suggests any reasons why high reliabilities cannot be sustained along with 90 percent removal levels. In fact, those periods of time during which high removal levels have been achieved in performance tests indicate that lime spray drying systems are capable of achieving high performance levels with high reliability levels. In addition, performance guarantees for commercial spray drying systems are available for 90 percent SO₂ removal and 95 percent system reliability.

2.8.2 Fluidized Bed Combustion

1. Comment: A number of commenters expressed the opinion that fluidized bed combustion (FBC) has not been demonstrated to achieve 90 percent SO₂ removal in industrial applications. Several (IV-D-23, IV-D-26, IV-D-30, IV-D-40, IV-D-43, IV-D-50, IV-D-53, IV-D-58, IV-D-62, IV-D-66, IV-D-73, IV-D-74, IV-D-81, IV-D-84, IV-F-1.1, IV-F-1.8, IV-F-1.16) said the data base cited in the proposal does not support the contention that an FBC unit can achieve 90 percent SO₂ control on a 30-day rolling average basis. They contended that the data on which this conclusion was based are one-time, short-term programs which are not representative of long-term emissions. Further, the commenters said, the monitoring used in collecting the data did not include continuous monitors on the inlet and outlet, or coal sampling and analysis on units of a size similar to those being regulated. The commenters felt that until sufficient data are collected, FBC should be classified as an emerging technology.

Others (IV-D-6, IV-D-26, IV-D-28, IV-D-30, IV-D-38, IV-D-40, IV-D-50, IV-D-52, IV-D-53, IV-F-1.18) agreed, saying that new technologies, such as FBC, currently lack sufficient operating data upon which to base NSPS regulations. The commenters expressed concern that the inclusion of such units in the standards could seriously impede the full demonstration and acceptance of this technology. Another commenter (IV-F-1.19) added that industry as a whole has little more faith in FBC units than they do in other FGD systems, since their availability and reliability have not yet met industry expectations. One commenter (IV-F-1.16) also felt that the high reliabilities required by industrial steam users have not been demonstrated with FBC systems. The commenter said that the only long-term reliability data presented in support of the proposed standards show 92 and 93 percent, which is not up to normal industrial requirements.

Response: Sufficient short-term performance test data exist to demonstrate that FBC technology is capable of achieving 90 percent SO₂ removal. Short-term data presented in the "Summary of Regulatory Analysis" show that several FBC units achieved 90 percent or greater SO₂ control during the test periods.

Long-term data also demonstrate that FBC units are capable of achieving greater than 90 percent SO₂ removal at high reliability levels. A recent 30-day test on a bubbling bed FBC unit burning high sulfur coal showed SO₂ removal efficiencies averaging 93.5 percent. A 30-day test conducted at a different site showed an average SO₂ removal of 90 percent with greater than 99 percent reliability. During a 67-day period at this site, the FBC unit had a

reliability of 97 percent. In addition, vendors have stated that FBC units can be designed to achieve well over 90 percent SO₂ removal at high reliability levels.

Approximately 21 coal-fired FBC units are currently operating in the industrial, commercial, and institutional sectors in the U.S. with heat inputs of 22 MW (75 million Btu/hour) or greater. Nineteen more in this size range are now being planned or are under construction. Given the numbers of FBC units in operation and in the planning/construction stage and the performance of operating units, FBC is considered a demonstrated technology.

2. Comment: Several commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-52, IV-D-53, IV-F-1.16) stated that the analysis of FBC performance in support of the proposed standards did not recognize the technological differences between atmospheric FBC and pressurized FBC, nor the variety of atmospheric FBC technologies such as bubbling bed, circulating bed, and dual bed.

Response: Pressurized FBC technology is still in the development stages and is not considered a demonstrated technology for the purpose of setting standards. As a result, in-depth analyses were not conducted on pressurized FBC systems. As discussed in the "Summary of Regulatory Analysis," however, atmospheric FBC is considered a demonstrated SO₂ control technology; thus, discussion of FBC is limited to atmospheric FBC systems.

Differences in the design and performance of bubbling, circulating, and dual bed atmospheric FBC units are discussed in the "SO₂ Technology Update Report" and in

"Fluidized Bed Combustion: Effectiveness as an SO₂ Control Technology for Industrial Boilers." Relative advantages and disadvantages among these designs are also discussed. Emission test data for five FBC units presented in the "Summary of Regulatory Analysis" demonstrate that greater than 90 percent SO₂ removal can be achieved using FBC technology. Although these data are based on bubbling bed designs, equal or better performance is expected from circulating and dual bed systems because of more rapid carbon burnout, higher limestone particle densities in the freeboard area, and more uniform gas-solid contact between SO₂ and limestone.

2.8.3 Other Technologies

1. Comment: Three commenters (IV-D-40, IV-D-52, IV-F-1.8) said that although the use of low sulfur coal or physical coal cleaning were determined to be "demonstrated technologies," they have been virtually eliminated by the percent reduction requirement. The commenters felt that all demonstrated technologies should be available for use in complying with the standards.

Response: The use of low sulfur coal and physical coal cleaning to control emissions of SO₂ was discussed in "Summary of Regulatory Analysis." While these two techniques were determined to be demonstrated methods of reducing SO₂ emissions, neither one was found to be capable of achieving reductions equivalent to those achieved by SO₂ control systems considered the "best demonstrated technology" under Section 111 of the Clean Air Act.

It should also be noted that the Congressional Record for the 1977 Clean Air Act amendments indicated that a percent reduction should be "based" on a "best demonstrated technology" capable of achieving emission reductions in the range of 85 to 90 percent [H. R. Rep. No. 1175, 94th Cong., 2nd Sess. 162 (1976)]. This report continued, "...use of coal washing alone (which results in up to 40 percent sulfur removal) would not constitute a suitable substitute, even though the economic and energy impacts of mechanical coal washing may be significantly lower than flue gas desulfurization." Therefore, conventional coal cleaning technologies clearly cannot serve as the "basis" of an NSPS.

Both low sulfur coal and physical coal cleaning, however, are available under certain circumstances. The use of low sulfur coal to meet an SO₂ emission limit is allowed for steam generating units operating at low capacity utilization factors. In addition, any reduction in potential SO₂ emissions achieved through the use of physical coal cleaning (or other fuel pretreatment methods) can be credited toward the percent reduction requirement, thus reducing the SO₂ removal efficiency required by the FGD system.

2.9 INDUSTRY-SPECIFIC ECONOMIC IMPACTS

1. Comment: Several commenters (IV-D-16, IV-D-19, IV-D-24, IV-D-25, IV-F-1.2) said the anthracite mining industry in Pennsylvania would be dealt a severe blow by a percentage reduction requirement because a very low sulfur coal would no longer be marketable. One (IV-D-16) added that the elimination of anthracite as a viable fuel choice would place a severe strain on the pension funds of over 7,000 former and 1,000 active anthracite miners. The

commenter supported this by saying that the pension fund is financed on the basis of the amount of anthracite produced and sold.

Response: The final standards do not eliminate anthracite as a viable fuel choice for industrial-commercial-institutional steam generating units.

As discussed previously, an exemption from the percent reduction requirement has been provided for steam generating units operating at low capacity utilization rates for coal or oil and meeting certain emission limits. Fuels with relatively low sulfur contents, such as anthracite, may therefore become more attractive for steam generating units operating at low capacity factors, especially for those located near anthracite deposits in the northeastern United States.

2. Comment: Three commenters (IV-D-28, IV-D-96, IV-F-1.2) said no thought has been given to the negative impact of pending new tax laws on capital investment. They said capital investments are going to become even more dire than they have been in recent years, further suppressing the already sluggish steam generating unit market.

Response: The Tax Reform Act of 1986 repealed the investment tax credit and modified the depreciation periods and methods for capital investments. These Federal income tax changes are offset, to some extent, by the lower business income tax rates that were instituted. Although repeal of the investment tax credit does increase the after-tax costs of capital-intensive projects such as the construction of a steam generating unit, there is no reason to assume that any

additional capital costs associated with compliance with the NSPS, over the costs of the steam generating unit itself, would cause a decision regarding whether or not to purchase a steam generating unit to change. It could, however, have an effect on the fuel selection for the new steam generating unit. In those instances where the additional capital investment required to install an FGD system is judged to be significant, source operators would be more likely to fire alternative fuels, such as natural gas, to avoid these additional capital costs.

3. Comment: Several commenters (IV-D-26, IV-D-46, IV-D-51, IV-D-52, IV-D-60, IV-D-73, IV-D-77, IV-D-88, IV-F-1.9) said the costs associated with the regulation will be reflected in the cost of goods, affecting the competitiveness of U.S. industry in the world market. They asserted that marginal changes in production costs can often push product prices beyond the limits of market acceptance. Another commenter (IV-D-44) was also concerned about the international competitiveness of U.S. industry. The commenter said that there is a substantial risk that oil and gas prices will skyrocket, and if U.S. industry is dependent on those fuels as a result of the NSPS, it will be in a very poor position to compete in international markets. According to the commenter, this would negatively affect the trade deficit.

Response: As discussed in the "Summary of Regulatory Analysis," an economic analysis was performed to assess the impacts of the standards on individual plants, with an emphasis on steam-intensive industries. The analysis was done assuming that all facilities would be subject to a percent reduction requirement, and thus represents a "worst case" assessment. This analysis estimated that product prices would increase

by less than one percent, even assuming full cost pass-through of the costs imposed by the standards to product prices. In addition, the analysis concluded that there would be negligible impacts on return on assets and debt/equity ratios as a result of the standards. Steam generating costs generally represent a small fraction of total manufacturing expenses.

The standard does not force industrial steam users to become dependent on any particular fuel. However, it is true that some operators will select natural gas to avoid the costs associated with the standard; therefore, there could be a greater proportion of natural gas-fired steam generating units than would occur in the absence of the NSPS. Projections of natural gas supply and price, however (see Section 2.6.1), indicate that natural gas supplies will remain more than sufficient to meet the demand, and prices are expected to increase very gradually throughout the remainder of this century. Therefore, the impacts of the standard as it relates to national energy markets, and thus to foreign competitiveness, are small.

4. Comment: Several commenters were concerned about the impact of the standards on the coal mining industry. Some (IV-D-14, IV-D-26, IV-D-36, IV-D-52) said the negative employment consequences in the coal mining industry, as well as the manufacturing and commercial sectors, far surpass the air quality benefits of the proposed standards. They estimated that the total coal mining ancillary jobs lost as a result of this NSPS could amount to 36,000 persons. Others (IV-D-40, IV-D-52, IV-D-83, IV-D-87) agreed, saying that because the standard will affect the existing market share of coal in the industrial fuel market as well as the new

market share, not only new jobs will be affected. They asserted that this impact has not been analyzed. The commenters estimated that rather than a loss of 5 million tons and 1,000 jobs, the actual displacement will be 40 to 50 million tons and 10,000 to 29,000 existing jobs. Another commenter (IV-D-27) expressed concern that the economy of those States in which coal production plays a major role could experience significant adverse impacts as a result of the standards with no significant benefit in terms of improved air quality.

Response: No negative employment consequences in the coal mining industry are expected to result from these standards. It is anticipated that the recent decline in oil prices will result in few coal-fired steam generating unit orders in the near future, even in the absence of the NSPS. Because of this, the revised national impacts analysis shows essentially no projected impacts on coal use due to the promulgated standard in the fifth year following proposal. The levels of oil and natural gas prices in the future will have a far greater impact on coal use in new steam generating units than any emission control standards.

The current industrial coal-fired steam generating unit market (about 50 million tons/year) is only a small fraction of total current coal production (over 800 million tons/year). The amount of this coal market that could be displaced as a result of the standard ranges from zero to five million tons/year in 1990, a very small fraction of the total coal market. In addition, total coal production is expected to increase to meet the demand from new electric utility power plants, more than offsetting any decline in coal demand that might occur in the industrial sector.

5. Comment: Two commenters (IV-D-51, IV-D-88) addressed the impacts of the standards on small businesses. They said the standards will affect small businesses, especially those which sell oil for use in industrial steam generating units. They further stated that standards will cause many steam generating unit owners who fire oil to switch to natural gas, causing the oil marketers to lose both present and future customers. The commenters felt that an initial Regulatory Flexibility Act analysis should be conducted to address the impact of the proposed standards on small businesses, particularly petroleum marketers who may be greatly affected by fuel switching from oil to natural gas.

Response: The Regulatory Flexibility Act requires assessment of impacts on "affected facilities" (in this case, the steam generating units) operated by small businesses, rather than on suppliers to the affected facilities. As a result, formal review of the impact of the Regulatory Flexibility Act on oil suppliers is not required.

While it is true that some steam generating unit operators may elect to fire natural gas instead of oil in response to the standards, this is expected to have little overall impact on the total U.S. oil market. Oil consumption by U.S. industry in 1986 was 8,340 PJ (7,900 TBtu). By comparison, the quantity of fuel switching from oil to natural gas projected by IFCAM is 120-330 PJ (110-310 TBtu) per year, or roughly 1-4 percent of 1986 industrial oil use. Further, because of factors not evaluated by IFCAM this estimate of fuel switching may be overestimated. Therefore, the NSPS will have little or no effect on most oil distributors.

2.10 SECONDARY ENVIRONMENTAL IMPACTS

2.10.1 Air

1. Comment: Two commenters (IV-D-21, IV-F-1.4) felt that if district steam systems are forced to shut down due to excessively stringent standards, steam customers would have to produce their own steam. According to the commenters, this would be done largely with less efficient and less well-controlled steam generating units that would not be subject to the NSPS. Therefore, the commenters said, local emissions would increase, a factor that was not considered in the impacts analyses.

Response: The standards would not require any existing facility to shut down, since the standards apply only to new steam generating units. If as a result of the standard there are more new small steam generating units built and fewer large district heating system steam generating units built, this would not necessarily result in an increase in emissions. The smaller the steam generating unit, the more attractive natural gas and oil become over coal. Coal is an attractive fuel only in large units. Consequently, smaller steam generating units would be expected to fire natural gas or premium oils (residual oils frequently require heating and pumping systems for constant circulation and heating to reduce viscosity). Premium oils also tend to have low sulfur contents. As a result, the emissions from the small steam generating units could well be less than the emissions from the large coal-fired district heating system steam generating units, even with controls applied. In any event, standards of performance for small steam generating units are under development and those standards will eliminate any

incentive created by these standards to replace large district heating system steam generating units with numerous small steam generating units.

2. Comment: Several commenters addressed the analysis of ambient impacts presented in the proposal. Some (IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-F-1.14) said the analysis showed that the proposed regulations may cause a deterioration in ambient air quality. However, they said, not enough information was provided to duplicate the modeling analysis or to determine a 3-hour or a 1-hour impact. The commenters also said there were no modeling results for hilly terrains, which are common in the eastern United States. One commenter (IV-D-81) noted that the impact on ambient air quality may be greater for a steam generating unit with an FGD system than for one using low sulfur fuel. The commenter said that a modeling demonstration in the "Summary of Regulatory Analysis" indicates that the maximum 24-hour downwind concentration for a 44 MW (150 million Btu/hour) steam generating unit would be higher with a 90 percent reduction and an emission rate achieving 50 percent of the standard than with a low sulfur fuel that just meets the standard.

Response: Modeling of ambient air quality impacts in the "Summary of Regulatory Analysis" was limited to two 150 million Btu/hour steam generating units, one firing oil and one firing coal. In both cases, percent reduction was based on "wet" scrubbing of the highest sulfur fuel reasonably available. Due to flue gas cooling with wet FGD and the resulting decrease in plume buoyancy, use of wet FGD will have poorer air dispersion characteristics than dry FGD systems. Despite this "worst case" approach, of the four cases examined (i.e., annual and 24-hour ambient concentrations

from oil- and coal-fired units), ambient impacts were 20 to 30 percent lower with percent reduction in both of the oil cases. In the two coal-fired cases, ambient impacts are roughly equal (FGD ambient impacts were roughly 5 percent lower on an annual basis, but 7 percent higher on a 24-hour basis).

Given this uncertainty, there are probably some situations, such as hilly terrain as mentioned by the commenter and short averaging times, in which the use of wet FGD systems could result in higher ambient air quality impacts than use of low sulfur fuel. It is expected that where site-specific modeling shows this to be the case, other air quality programs, such as prevention of significant deterioration and new source review (i.e., PSD and NSR), will ensure that appropriate techniques are employed to maintain and protect ambient air quality. Such techniques include dry FGD processes and stack gas reheat, both of which result in higher flue gas temperatures and greater flue gas dispersion.

Finally, protection of air quality cannot be limited to assessment of short-term, short-range dispersion of pollutants. Of particular concern with SO_2 emissions is their impact on sulfate levels, which are of significance to acid rain. While the magnitude of the acid rain problem and the benefits of various solutions are still the subject of research and debate, it is clear that sulfates are a contributor. From the perspective of total sulfate loadings, FGD technologies are more effective than use of low sulfur coals and thus have benefits not captured in the ambient air modeling cases discussed above.

Each of the above factors, plus many others, were taken into consideration prior to adoption of the final standards.

2.10.2 Water

1. Comment: Several commenters said the impacts of a standard "based" on the use of FGD systems had not been evaluated in relation to other regulations. Two commenters (IV-D-26, IV-D-78) said the analyses did not address the impact of sodium FGD system waste on water quality regulations such as effluent limitations guidelines for various industrial categories or water quality standards which could impose stringent effluent limitations on wastewater treatment plants. Another (IV-D-62) stated that no consideration has been given to the fact that some States' water quality criteria include limits on osmotic pressure, dissolved solids, and sodium sulfate because of the potential for causing harm to irrigated crops. Several commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-F-1.15) noted that California has classified the effluent from sodium FGD systems as a "designated" waste requiring special handling, such as hauling to a secured disposal site. The commenters felt that other States may follow suit on this lead, creating a major waste disposal problem. Also, the commenters said, the standards encourage complete oxidation of sulfites to sulfates prior to discharge of sodium FGD system wastewater streams. However, they noted that some municipalities have adopted a sulfate limitation of 250 mg/l for discharges into treatment works and said this has not been considered in developing the NSPS. Another commenter (IV-D-78) said that the cost implications of FGD system wastewater treatment for zero-discharge facilities were not adequately discussed.

Response: The limits imposed by existing regulations on the disposal of wastewater streams from sodium FGD systems were examined by reviewing current disposal practices for these types of wastes. Wastewater streams from sodium FGD systems are not considered hazardous wastes, even under the most stringent State or local regulations. In the West, disposal of these types of wastes is generally by deep well injection or above-ground evaporation or percolation ponds. In the East, disposal of these types of wastes is generally by direct discharge to a receiving water body or indirect discharge through a POTW. These streams are often treated prior to discharge by oxidation, dilution, and/or removal of suspended solids to comply with State or local effluent limitations, water quality standards, or POTW pretreatment standards. Thus, while pretreatment may be necessary in some cases, these types of wastewater streams are currently being disposed of by several methods in compliance with State and local regulations.

The cost algorithm for sodium FGD systems included costs for oxidation in order to reflect some form of pretreatment prior to disposal. In some cases, however, even with pretreatment of the wastewater streams, some forms of disposal, such as direct or indirect discharge, may not be permitted. This could happen in areas of high industrial usage where the receiving water body and/or POTW has reached its maximum pollutant load. In addition, it is also possible in some cases that disposal by deep well injection, evaporation ponds, or landfill containers may not be permitted. This could happen in areas where concerns about possible contamination of underground aquifers are paramount, effectively prohibiting disposal of any liquid wastes by such means.

For this reason, as well as other reasons, the standard is not "based" on the use of sodium FGD systems alone, nor for that matter does the standard require the use of any particular FGD system or SO₂ control technology. Rather, the standard reflects the level of control that is achievable through the use of any one of several technologies, including sodium FGD systems, dual alkali FGD systems, lime/limestone FGD systems, lime spray drying, and fluidized bed combustion. In addition, where an individual confronted with the standard may view the "burden" of using these control technologies as excessive, fuel switching to natural gas can be employed. In this manner, the necessity of using these SO₂ control technologies can be avoided.

As discussed throughout the "Background Information Document," the "SO₂ Control Technology Update Report," and the "Summary of Regulatory Analysis," the environmental (i.e., air, water, and solid waste), energy, cost, and economic impacts associated with use of all of the above-mentioned SO₂ control technologies, as well as those associated with fuel switching, were reviewed and are considered reasonable. Consequently, in areas where disposal of wastewater streams from sodium FGD systems, or for that matter wastewater streams from any "wet" FGD system, is found to be very costly or essentially prohibited by local regulation, steam generating units would be expected to select an alternative approach to complying with the standard. Such alternatives could range from the use of "dry" scrubbing systems (i.e., lime spray drying or fluidized bed combustion) to the use of natural gas.

2. Comment: One commenter (IV-D-48) expressed concern that for plants producing only solid wastes, addition of a liquid waste stream would represent a major shift in disposal requirements.

Response: As discussed above, the standard is not "based" solely on "wet" SO₂ control technologies (i.e., technologies which produce wastewater streams requiring disposal). In addition, the standard does not require the use of any particular control technology. Consequently, a plant that produces only solid wastes from its production process would most likely select an SO₂ control option that produces a solid waste, such as lime spray drying or fluidized bed combustion, or, alternatively, would fire a fuel not requiring the use of SO₂ control, such as natural gas.

3. Comment: Five commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-F-1.16) stated that no data were presented on the characteristics of wastewater from sodium FGD systems serving coal-fired steam generating units. According to the commenters, treatment of this wastewater could include neutralization, oxidation, metals precipitation, and solids sedimentation, and could be very costly. Moreover, the commenters said, there may be discharge problems with even this treated waste stream due to high total dissolved solids (TDS) content.

Response: The typical concentrations of trace metals in the wastewater stream from a sodium FGD system on a coal-fired steam generating unit were estimated based on a review of the trace metal concentrations typically present in the wastewater streams generated from other "wet" scrubbing systems, such as lime/limestone scrubbing systems, operating on coal-fired steam generating units, as well as consideration of the known entities present in the coal and the reagents used in the FGD system. This was discussed in the "Summary of Regulatory Analysis" and a memorandum entitled "Overview of the Sodium Wet Scrubbing Technology."

Other characteristics, such as the dissolved solids concentration, were also estimated from review of the range of values typically observed in the wastewater streams discharged from sodium FGD systems operating on oil-fired steam generating units and adjusted for various differences between oil and coal, such as the typically higher SO₂ and trace metal loadings in the flue gas from coal-fired units. A wide range of concentrations was presented for each element, in order to include values for low and high sulfur coal, and pulverized and spreader stoker type steam generating units.

No data were presented by commenters, nor did any commenters challenge the validity of these estimates by pointing out errors that may have been made. Consequently, these estimates of the characteristics of the wastewater streams discharged from sodium FGD systems operating on coal-fired steam generating units are considered valid.

4. Comment: Several commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-D-73, IV-F-1.15) said the assumption that FGD system water usage will be only a small fraction of the total plant demands may be true for water-intensive industries such as iron and steel or refineries, but could be significant for other industries. The commenters felt that these other industries should be examined.

Response: Again, as mentioned above, the standards do not require the use of "wet" FGD systems. In addition, the amount of water required by wet FGD systems should not pose a problem in most cases. However, there may be some situations (such as location in an arid area or at a plant that has a low overall water need) where this additional water usage would

be significant. In such situations, alternative control options could be selected (such as dry scrubbing, fluidized bed combustion, or firing an alternative fuel such as natural gas) to minimize or eliminate this additional water requirement. As discussed above, the costs associated with these alternative approaches to SO₂ control are considered reasonable.

5. Comment: Two commenters (IV-D-26, IV-D-73) said the sodium salts which are discharged to a wastewater treatment plant as part of the effluent from a sodium FGD system increase the total influent total dissolved solids (TDS) concentration. This, in turn, causes high effluent total suspended solids (TSS) concentrations and also inhibits the ability to reduce effluent TSS by the use of polyelectrolytes. They said that higher TDS and temperature of the wastewater effluent can also act to inhibit the mass transfer of oxygen into water and encourage oxidation of sulfite to sulfate, requiring additional deaeration capacity in the wastewater treatment plant.

Response: This may be true in some cases. In fact, as discussed earlier, the wastewater streams from sodium FGD systems are generally pretreated by dilution, oxidation, and/or removal of suspended solids prior to discharge. Thus, the cost algorithm for sodium FGD systems included costs for oxidation to reflect additional costs for some type of pretreatment prior to disposal.

As also discussed earlier, however, the standard does not require the use of sodium FGD systems or, for that matter, any specific SO₂ control technology. Thus, in cases where the use of sodium FGD systems would result in deterioration

of the overall quality of the wastewater effluent discharged from a manufacturing plant to the point where additional and costly increases to the wastewater treatment system would be needed, other alternatives such as lime spray drying, fluidized bed combustion, or combustion of natural gas could be selected.

6. Comment: Several commenters expressed concern about the effects of wastewater effluent from a sodium FGD system on small wastewater treatment plants. Two (IV-D-26, IV-D-73) said for a small wastewater treatment plant near its hydraulic capacity, the additional flow from a sodium FGD system may be enough to overload the system. The consequence of this overload, the commenters said, would be a reduction in effluent quality. Others (IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-F-1.15) noted that the conversion of sulfates and sulfites in the wastewater stream from a sodium FGD system to hydrogen sulfide can create an odor problem. They said the analysis of this problem focused on large POTW's where no problems were encountered. However, the commenters felt that analysis of a small municipal treatment plant with less flow should be conducted.

Response: Small POTW's or municipal wastewater treatment plants could be unable to accept the wastewater stream from a sodium FGD system if they are already operating near their maximum pollutant load. Also, poorly designed or poorly operated wastewater treatment plants, which fail to maintain aerobic conditions throughout the treatment system, could give rise to odor problems as a result of conversion of sulfates/sulfites to hydrogen sulfide. Odor problems can be mitigated by oxidizing the wastewater stream from a sodium FGD system prior to discharge and by proper operation of the

wastewater treatment plant to maintain aerobic conditions. This is generally done at POTW's by injecting air into the sewer lines and ensuring that the sewer flow does not become stagnant, and by aeration of ponds and lagoons. Odor problems are generally not related to the size of the POTW, but rather to the proper maintenance of aerobic conditions in the system. Again, as mentioned above, the standards do not require the use of any particular control system and where problems of this nature may exist, alternatives to the use of sodium FGD systems could be selected.

2.10.3 Solid Waste

1. Comment: Several commenters expressed concern about the availability of adequate landfill capacity to dispose of FGD system waste. Some (IV-D-26, IV-D-29, IV-D-30, IV-D-50, IV-D-52, IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-84, IV-F-1.16) stated that most FGD processes produce a waste sludge that requires costly and space consuming disposal in increasingly scarce landfill capacity. For example, they asserted, to remove 600 Mg/year (660 tons/year) of SO_2 from high sulfur coal, 7,250 Mg (8,000 tons) of solid waste would be generated. The commenters felt that the focus on relative rather than absolute increases in waste volume is inappropriate. Another (IV-D-44) said that although the proposal claims that there is adequate capacity for disposal of wastes generated by FGD systems, no study was cited to support this claim. The commenter said that according to figures contained in the proposal document, the use of FGD systems could generate approximately 15 times as much waste as the use of low sulfur coal. The commenter asserted that there is no evidence in the record of landfill capacity sufficient to handle a fifteen-fold increase in waste.

Another commenter (IV-D-78) added that State and local solid waste disposal regulations are forcing the closure of many existing landfills, making the siting of proximal landfills difficult or impossible, and driving up the cost of disposal in available municipal landfills. The commenter said these impacts were not addressed in the proposal. Another commenter (IV-D-62) said that until a means is found to site landfills where they are needed without endless lawsuits and other legal maneuvers impeding the process, the Agency should allow the use of "compliance fuels" having a sulfur content low enough to meet the numerical emission limit without the use of FGD systems.

Response: Steam generating units do not generally operate as independent entities, but are most often part of an industrial plant which itself produces wastes requiring disposal. In addition, coal-fired steam generating units generate fly ash which also requires disposal. Thus, use of an FGD system to control SO_2 emissions generally does not create a new problem (i.e., a need to dispose of wastes where no such need existed before).

As discussed in the "Summary of Regulatory Analysis," the use of dual alkali or lime spray drying FGD generates less than twice as much solid waste as the use of low sulfur coal, rather than fifteen times as suggested by the commenters. For example, the use of low sulfur coal would generate about 3,200 Mg/yr (3,500 tons/yr) of solid waste (steam generating unit blowdown and ash) from a typical 44 MW (150 million Btu/hour) steam generating unit. The use of a dual alkali FGD system to achieve a 90 percent reduction in SO_2 emissions from a steam generating unit firing this same coal would generate an additional 1,200 Mg/yr (1,300 tons/yr) of solid waste (FGD sludge).

In most cases, disposal of wastes generated by FGD systems presents no more of a problem than disposal of plant wastes or steam generating unit fly ash. As a result, FGD system wastes may generally be disposed of by the same means as these wastes. In fact, since the wastes from some industrial plants are considered toxic or hazardous and FGD system wastes are not, disposal of wastes from FGD systems may present less of a problem than disposal of plant wastes.

Consequently, in those specific locations where landfill capacity may be limited, disposal of plant wastes is likely to present as many problems -- and in some cases more problems, given the nature of certain plant wastes -- as disposal of wastes from FGD systems. For the plant, such constraints may necessitate substantial changes to the manufacturing process in order to minimize the wastes generated or to alter their characteristics. For the steam generating unit and SO₂ control system, this may necessitate selection of one type of control system over another (i.e., a "dry" system over a "wet" system, for example) or selection of an alternative fuel, such as natural gas, with little or no waste disposal requirements.

2. Comment: Several commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53) said the potential effects of fabric filter bag failures on the operation of a wet FGD system which is not designed for particulate removal were not evaluated. They felt that the consequent effect of the increase in particulate loading on the FGD system operation and the FGD system effluent should be evaluated.

Response: A fabric filter bag failure should only be a temporary and infrequent occurrence in a well operated and maintained system. In addition, the typical baghouse is constructed with multiple compartments, allowing one compartment to be shut down (bypassed) for routine cleaning, maintenance, or repairs without affecting the overall particulate matter collection efficiency of the baghouse. Within each compartment are multiple fabric filter bags, so that even if one of these bags were to rupture or fail, the amount of particulate matter passing through the compartment that remained uncollected would not be significant and should not appreciably affect either the FGD efficiency or the FGD system effluent.

3. Comment: Several commenters (IV-D-10, IV-D-44, IV-D-82, IV-D-83) asserted that higher percent reduction requirements increase solid waste impacts due to additional absorbent use with no discernible air quality benefits over lower percent reduction requirements.

Response: Higher percent reduction requirements do result in additional absorbent use and, therefore, larger quantities of solid waste than do the lower percent reduction requirements. However, the impacts associated with waste disposal are unlikely to be significantly different whether the percent reduction requirement is 90 percent, 70 percent, or even 50 percent. The estimates of waste quantities developed for this analysis were based on 92 percent SO₂ removal and, therefore, represent conservative estimates. In addition, a 90 percent reduction requirement results in significant emission reductions over a 50 or 70 percent reduction requirement, and the impacts associated with 90 percent reduction (including waste disposal) are considered reasonable.

4. Comment: One commenter (IV-D-48) claimed that FGD waste disposal is not "easy" as was stated in the proposal. The commenter cited an example in which a recently granted permit to dispose of dry FGD waste in Minnesota required a leachate collection system, an impermeable plastic liner, a detailed closure plan, pre- and post-operational monitoring plans, and a performance bond. Others (IV-D-44, IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-84) agreed, saying some States, such as North Carolina and Minnesota, do not allow disposal of FGD system waste in an unlined landfill, due to the risk of groundwater contamination. They warned that this could create a waste disposal problem.

Response: As discussed previously, steam generating units do not generally operate independently, but as part of an industrial plant which, even in the absence of the steam generating unit, would produce wastes requiring disposal. In addition, the steam generating unit itself produces fly ash that must be disposed of even in the absence of FGD system wastes. The wastes produced by dry SO_2 control techniques, such as lime spray drying and fluidized bed combustion, are not classified as hazardous and generally can be disposed of in landfills without special handling. In fact, the wastes produced as a result of the manufacturing process may actually be more difficult to dispose of than FGD system wastes, due to hazardous or toxic materials present during the manufacturing process.

There may be specific locations, however, where strict State or local waste disposal requirements exist. In these cases, constraints on disposal of plant wastes would likely be as stringent as, or even more stringent than, constraints on FGD system waste disposal (depending on the nature of the

plant waste). Consequently, in those specific locations where landfill capacity may be limited, disposal of plant wastes is likely to present as many problems -- and in some cases more problems, given the nature of certain plant wastes -- as disposal of wastes from FGD systems. For the plant, such constraints may necessitate substantial changes to the manufacturing process in order to minimize the wastes generated or to alter their characteristics. For the steam generating unit and SO₂ control system, this may necessitate selection of one type of control system over another (i.e., a "dry" system over a "wet" system, for example) or selection of an alternative fuel, such as natural gas with little or no waste disposal requirements. As mentioned previously, the costs associated with the use of alternative FGD systems or the use of alternative fuels, such as natural gas, were examined and are considered reasonable.

5. Comment: Several commenters mentioned the uncertainty concerning the definition of FGD system sludge under the Resource Conservation and Recovery Act (RCRA). Some (IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-84) said that although FGD system sludge at present is specifically exempted from the definition of hazardous waste under RCRA, that exemption is not necessarily permanent. They stated that if a study which is currently being conducted indicates that FGD system sludge should be reclassified as hazardous, this could significantly affect the NSPS analysis. Even if FGD system sludge is not designated a hazardous waste, the commenters said, the Agency is required under the new RCRA amendments to develop Subtitle D Non-Hazardous Waste Regulations. The commenters felt these regulations could significantly increase the requirements for disposal of FGD system sludge.

One commenter (IV-D-66) said the analysis of the secondary impacts of the proposed standards leaves questions unresolved: Would State agencies allow the disposal of FGD system solid and sludge wastes with other nonhazardous wastes? Will developments in waste testing procedures result in determining FGD system wastes to be hazardous? Did the Agency test actual sludges for hazardous constituents? If FGD system wastes are found to be hazardous, would companies be required to establish hazardous waste landfills?

Response: In developing emission standards, it is necessary to consider the impacts of these standards on existing regulations, as well as the impacts of existing regulations on the standards. Sludge produced by FGD systems is currently considered to be a nonhazardous waste under RCRA. If further study indicates that it should be reclassified as hazardous, this will be taken into account during the regular NSPS review process in assessing the impacts of revising the standards.

6. Comment: Three commenters (IV-D-44, IV-D-82, IV-F-1.10) said the increase in FGD system sludge resulting from this regulation is counter to the principle of not blindly requiring the shifting of pollutants between media to solve a pollution problem. Another commenter (IV-D-83) said too little or no attention has been given to the cross-media aspects of these regulations. The commenter said that although the proposal recognized that the standards will increase the output of solid and liquid wastes, it stated that this increase would be insignificant compared to the large amount of waste already generated by these facilities. According to the commenter, this runs counter to the current trend that the

generation of all solid wastes should be reduced, not increased. The commenter contended that any regulation which results in the generation of more wastes should be subjected to stricter scrutiny than these appear to have been.

Response: The secondary environmental impacts of the final standards were examined, including impacts on ambient air quality, water quality, and solid waste generation and disposal. All regulations which control pollution in one area will result in some "cross-media" pollution impacts in another; a determination must be made as to whether these impacts are "unreasonable" given the benefits of pollution reduction associated with the standard. The impacts of these standards on other environmental media were reviewed by the Agency and are considered reasonable in light of the reduction in emissions of SO_2 achieved by the standards.

2.11 REGULATORY IMPACT ANALYSIS

1. Comment: One commenter (IV-D-64) stated that the Regulatory Impact Analysis (RIA) fails to account for the full range of benefits that would accrue from these emission reductions. Specifically, the commenter said, the RIA acknowledges that benefits due to reductions in acid deposition are ignored, as are the health benefits of expected reductions in sulfate concentrations. The commenter suggested that fuller elaboration of these two important items would provide an even stronger justification for the proposed standards.

Response: The commenter is correct in stating that the RIA does not present the full range of possible benefits from the proposed standards. Although complete coverage is

desirable, in this instance complete quantification is not needed to demonstrate the appropriateness of the standards.

2. Comment: One commenter (IV-D-76) asserted that there are some important shortcomings in the RIA that have resulted in an overstatement of benefits of SO₂ control. Specifically, the commenter said:

- the contingent valuation study used for visibility estimates has serious shortcomings that result in an upward bias in the benefit estimates for visibility;
- the morbidity benefits estimate omits a key variable - ozone - that results in inclusion of ozone morbidity in the PM/sulfates morbidity estimates, overstating the morbidity by one-half to one-third.

Response: The decision to use the contingent valuation study by Tolley, et al., to calculate the visibility benefits was reexamined in light of the commenter's concerns. In response to concerns that the Tolley study overestimated the benefits of visibility improvements, four other contingent valuation studies were examined for comparison.

Comparison of Tolley with these four studies leads to the following conclusions:

- The benefits estimated using the Tolley study were not significantly different from the benefits estimated using the other four studies.
- The use of Tolley, therefore, does not bias the visibility benefits upward.

As a result of this comparison and to provide a rigorous analysis, the RIA has been updated to include all five contingent valuation studies in estimating visibility benefits rather than relying solely on Tolley.

The commenter also noted that the study used to calculate PM morbidity (Ostro 1983) omitted ozone as a key variable. A more recent study by Ostro (1986) has been reviewed and replaces Ostro 1983 in the updated RIA.

The morbidity measure used in Ostro 1986 is limited to acute respiratory conditions only and is therefore a better measure of PM-induced acute morbidity than that used in his earlier study. The 1986 study also uses fine particles rather than total suspended particulate (TSP) as the measure of exposure. Since the smaller (or fine) particles are the most damaging to health, they are probably the most appropriate indicator of PM exposure.

Due to these analytical improvements made in the Ostro 1986 study, the reported relationship between PM and acute morbidity in adults is considered consistent, vigorous, and reliable.

3. Comment: Several commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-F-1.14) noted that in the RIA analysis of sulfate levels, there are only four States where estimated sulfate levels decrease from the base case to those achieved by a low sulfur fuel standard, and none of those is decreased further by imposing a percent reduction requirement. They further pointed out that, of the five other States showing any improvement by imposition of a percent reduction standard over a low sulfur fuel standard, none shows more than a 0.1 ug/m^3 improvement. The commenters felt that this cannot be deemed significant. The commenters also contended that similar results are seen in the analysis of visibility improvements contained in the RIA.

Response: In the draft RIA, Table III-3 (page III-7) shows that all 31 States analyzed under the low sulfur fuel alternative have estimated 1995 sulfate concentrations that are from 0.1 to 3.9 percent lower than the 1995 baseline emissions. State-by-State 1995 sulfate concentrations under the percent reduction alternative (Table III-4, page III-8) are 0.3 to 4.0 percent lower than the 1995 baseline. The apparent lack of change in sulfate concentrations noted by the commenters is due to round off of actual numbers to two digits when reported in the RIA. The draft RIA shows that the benefits resulting from the proposed standard are indeed significant and of the same order of magnitude as the costs.

4. Comment: Four commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53) asserted that the RIA shows that the actual costs of the standard can be higher than the value of the purported benefits.

Response: The draft RIA shows that the benefits and costs are of the same order of magnitude. The draft RIA also states that there are potentially significant benefit categories that are not included and other categories that are only partially covered. For example, the SO₂ benefit estimates include only calculations for reductions in residential materials damage. No calculations are included for commercial or industrial facilities. Potentially significant benefits are not included from the nonhuman biological effects category (e.g., acid deposition) and from the SO₂ health categories. In addition, as discussed earlier, the impacts associated with various standards were reexamined under revised energy scenarios. This analysis indicates that the costs associated with the final standards are considerably lower than those presented in the draft RIA.

5. Comment: One commenter (IV-D-96) said that the RIA should consider the effect of the recent Federal tax reforms on discretionary capital expenditures.

Response: Although the new Federal tax reforms have not been incorporated into the RIA, the revised tax system should not have a significant impact on capital expenditures for industrial-commercial-institutional steam generating units. A survey of new steam generating unit projects conducted in 1986 indicated that capital costs could increase by as much as 30 percent without significantly affecting the decision to purchase a new steam generating unit. Although the new tax revisions abolish the investment tax credit, this credit amounts to only 10 percent of the capital cost of the steam generating unit and, therefore, the decision to buy a new steam generating unit would not be affected.

6. Comment: One commenter (IV-D-96) felt that the baseline level of emissions used in the benefit analysis was too high, resulting in a significant overestimation of the benefits of the standards.

Response: The cost and benefit estimations are calculated from the same baseline and, as a result, if benefits are erroneously high then so are costs. The draft RIA presents benefits and costs that are of the same order of magnitude. Consequently, if the baseline emissions are reduced, then benefits and costs will also be reduced but will remain in the same order of magnitude. Also, as noted above, under the revised energy price scenarios, the cost estimates are greatly reduced, making the benefit-cost ratio associated with the final standards even more positive.

2.12 MIXED FUEL-FIRED STEAM GENERATING UNITS

1. Comment: Several commenters (IV-D-58, IV-D-62, IV-D-65, IV-D-66, IV-D-74, IV-D-84) said there is no need to revise the current NSPS for mixed fuel-fired steam generating units due to the small amounts of SO₂ emitted.

Response: Based on an analysis of mixed fuel-fired steam generating units, there is no justification for retaining the current NSPS for these units. Significant reductions in SO₂ emissions can be achieved by the revised standards, and the cost, energy, and environmental impacts associated with the revised standards are considered reasonable.

Mixed fuel-fired steam generating units are generally larger than many other types of industrial steam generating units and emit significant amounts of SO₂ as individual sources as well as from the group as a whole (a projected 69,000 tons year by 1990). For example, a typical 117 MW (400 million Btu/hour) heat input capacity mixed fuel-fired steam generating unit firing a mixture of 50 percent coal and 50 percent nonfossil fuel under the regulatory baseline would emit nearly 2,000 Mg (2,100 tons) of SO₂ annually. Even firing only 20 percent coal, this steam generating unit would emit almost 800 Mg (900 tons) of SO₂ annually. Therefore, mixed fuel-fired steam generating units are considered significant sources of SO₂ emissions.

The costs of controlling SO₂ emissions from these steam generating units were examined thoroughly and discussed in "An Analysis of the Costs and Cost Effectiveness of SO₂ Control for Mixed Fuel-Fired Steam Generating Units." This report analyzed the impacts associated with a number of

regulatory alternatives ranging from standards based on an emission limit only to standards requiring a percent reduction in SO₂ emissions from steam generating units firing various mixtures of sulfur-bearing and nonsulfur-bearing fuels. The impacts associated with standards requiring a percent reduction in SO₂ emissions were considered reasonable, with one exception. The cost effectiveness of standards requiring a percent reduction in emissions was considered unreasonable for mixed fuel-fired steam generating units with annual capacity utilization factors for coal or oil of 30 percent or less. Therefore, this subcategory of mixed fuel-fired steam generating units was granted an exemption from the percent reduction requirement but must comply with an emission limit to minimize SO₂ emissions.

2. Comment: A number of commenters felt that emission credits should be granted for mixed fuel-fired steam generating units. Two commenters (IV-D-26, IV-D-73) said many industrial steam generating units are burning more and more waste fuels which would otherwise be destined for off-site disposal. They felt this environmentally beneficial and cost effective effort should be encouraged, not discouraged. Several (IV-D-5, IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-D-58, IV-D-62, IV-D-65, IV-D-66, IV-D-74, IV-D-78, IV-D-84, IV-F-1.7) said the conclusion that there is no environmental benefit associated with allowing emission credits for the amount of nonfossil fuel fired in the steam generating unit is incorrect. They further stated that the assumption that steam generating unit operators increase the sulfur content of the coal or oil burned as the amount of nonfossil fuel burned in the unit increases is not borne out by operational experience, nor would this usually be allowable under PSD or

State regulations. Therefore, the commenters suggested that the conclusion not to allow emission credits be reexamined. If there is still concern on this matter, the commenters said, some minimum amount of nonfossil fuel firing (e.g., 5 percent) could be specified for a steam generating unit to qualify as a combination unit.

Other commenters focused on units firing natural gas in combination with coal or oil. Some (IV-D-11, IV-D-49, IV-D-57, IV-F-1.5) felt that the standard does not give natural gas equal treatment when used in combination with coal or oil because it does not consider gas as an energy input when calculating average emissions. They said this could deter the use of new and existing gas-related technologies such as co-firing, re-burn, or re-burn combined with sorbent injection. The commenters suggested that the standard be revised to allow any source that burns gas and another fuel to receive emission reduction credit for the amount of gas used. One commenter (IV-F-1.5) added that natural gas should be allowed a greater opportunity to aid reduction of SO_2 as well as NO_x emissions through co-firing with coal and oil as well as being a direct substitute for either. Others (IV-D-11, IV-D-15, IV-D-26, IV-D-28, IV-D-73) felt the regulation should allow steam generating unit operators to use any mixture of fuels to meet an applicable emission limit and to calculate emissions based on total energy input from all fuels. They said this would greatly improve the cost effectiveness of compliance for those sources using inherently clean fuels.

Response: Emission credits effectively negate any environmental benefits, in terms of reduced SO_2 emissions, associated with the combustion of nonsulfur bearing fuels in mixed

fuel-fired steam generating units. Emission credits would permit SO₂ emissions from a mixed fuel-fired steam generating unit to increase to the same level they would be if the steam generating unit fired only oil or coal. A mixed fuel-fired steam generating unit firing a 50/50 mixture of coal and wood waste, for example, would be permitted to emit twice the SO₂ emissions with an emission credit as it would without an emission credit.

The merits of emission credits for mixed fuel-fired steam generating units were thoroughly examined and discussed in "Summary of Regulatory Analysis," "An Analysis of the Costs and Cost Effectiveness of SO₂ Control for Mixed Fuel-Fired Steam Generating Units," and "Impacts of New Fuel Prices on SO₂ Emission Credits for Cogeneration Systems and Mixed Fuel-Fired Steam Generating Units." To assess the merits of emission credits, the costs, SO₂ emissions, and cost effectiveness of SO₂ control were analyzed with and without an emission credit. This analysis shows that granting an emission credit for mixed fuel-fired steam generating units results in very small reductions in costs while allowing significant increases in SO₂ emissions. Therefore, the incremental cost effectiveness of the additional reduction in SO₂ emissions achieved by not providing emission credits for mixed fuel-fired steam generating units is low, generally in the range of \$220-330/Mg (\$200-300/ton). These costs are considered reasonable in view of the significant additional emission reductions achieved by not providing emission credits. Consequently, the standards do not include provisions for emission credits for mixed fuel-fired steam generating units.

The absence of provisions for emission credits should not, however, discourage the use of on-site wastes as steam generating unit fuels. In most cases, the disposal of such wastes in this manner would represent the most cost effective method of disposal regardless of the NSPS. In addition, the final standards include an exemption from the percent reduction requirement for steam generating units firing oil or coal at 30 percent or less of their rated annual heat input capacity. This provides substantial incentive to fire on-site or off-site wastes in order to reduce the amount of oil or coal burned in the steam generating unit.

3. Comment: Two commenters (IV-D-5, IV-D-58) felt that the emission baselines used for mixed fuel-fired steam generating units were unrealistically high and did not reflect current emission levels. Specifically, they said that the use of a baseline emission level of 1,076 ng/J (2.5 lb/million Btu) for mixed fuel-fired units firing coal is unrealistic. According to the commenters, units larger than 73 MW (250 million Btu/hour) are already subject to a 516 ng/J (1.2 lb/million Btu) emission limit, and it is likely that smaller units would be subject to similar limits due to PSD/BACT limitations or State regulations. Therefore, the commenters said, a baseline of 516 ng/J (1.2 lb/million Btu) should be used and all cost effectiveness and emission calculations should be revised accordingly. The commenters also felt that a baseline of 1,290 ng/J (3.0 lb/million Btu) for units firing mixtures of oil and wood is unrealistic, and a more logical baseline would be 344 ng/J (0.8 lb/million Btu).

Response: The SO₂ emission limits of 1,076 ng/J (2.5 lb/million Btu) for coal-fired steam generating units and 1,290 ng/J (3.0 lb/million Btu) for oil-fired steam generating units represent the "average" emission limits currently required under SIP's for units with heat input capacities below 73 MW (250 million Btu/hour). Steam generating units larger than this size are, as noted by the commenters, subject to the Subpart D emission limits of 516 ng/J (1.2 lb/million Btu) for coal and 344 ng/J (0.8 lb/million Btu) for oil. The baselines for these larger units have been revised to reflect these levels in subsequent analyses.

4. Comment: One commenter (IV-D-79) said the final standards should clarify that only SO₂ emissions resulting from combustion of regulated fuels are subject to the standard. The commenter added that emissions of SO₂ that result from the combustion of other fuels, as in carbon monoxide boilers, should not be covered by the standard.

Response: The promulgated standard applies only to SO₂ emissions resulting from the combustion of coal and/or oil. Consequently, if a sulfur-bearing fuel other than coal or oil is combusted in combination with coal or oil, and if the contribution to emissions from that fuel can be separated from the contribution from coal or oil, those emissions would not be subject to the standards. The final standards have been clarified with regard to this point.

5. Comment: Several commenters (IV-D-5, IV-D-58, IV-D-62, IV-D-65, IV-D-66, IV-D-74, IV-D-84) requested that the source of "historical data" used to geographically distribute the projected 35 new mixed fuel-fired steam generating units be identified. They questioned why all of these units were

placed in Regions I, IV and X when there are numerous mixed fuel-fired steam generating units in other regions. For example, the commenters said, of the 35 mixed fuel-fired units installed from 1980-1984, 21 were in the South. They felt that the distribution used in the analysis gives undue emphasis to Regions I and X, and should be revised to give more weight to Regions IV and VI where the compliance costs are much higher.

Response: Regions I, IV, and X were selected for the purpose of analyzing the potential impacts of standards on new mixed fuel-fired steam generating units. Historically, these regions have had the highest concentration of the pulp and paper and forest products industries, and most of the existing mixed fuel-fired steam generating unit population is located in these regions. The information used to geographically situate the mixed fuel-fired steam generating unit population was discussed in "Nonfossil Fuel Fired Industrial Boilers - Background Information." This information was obtained from various directories of the pulp and paper and forest products industries.

In determining which regions to use for purpose of analysis, a number of factors were considered. While it is true that mixed fuel-fired steam generating units are located throughout the U. S., most new mixed fuel-fired steam generating units were expected to be sited in the northeast and southeast and on the west coast. Based on this determination, Region I (with 6 boilers) was selected to represent the northeast, Region IV (with 16 boilers) was selected to represent the southeast, and Region X (with 13 boilers) was selected to represent the west coast. Subsequent data collected as part of the boiler replacement

survey identified 30 mixed fuel-fired boilers built between 1981 and 1984. Of these, 21 were designed to burn a combination of coal and wood, while 8 were capable of also firing oil or natural gas. By geographic area, the 30 units were distributed as follows: 16 were located in the southeast, 8 were on the west coast, 3 were in the upper midwest, 2 were in the northeast, and 1 was in the southwest. Of the 16 in the southeast, 12 were in Region IV, 3 were in Region III, and 1 was in Region VI. Based on this review of regional data and comparison of regional fuel price estimates, it was concluded that the original placement of boilers and the analysis of cost impacts for compliance with a percent reduction standard were valid.

6. Comment: Several commenters (IV-D-5, IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-84) said the projection that 35 new mixed fuel-fired steam generating units with a total heat input capacity of 19×10^9 Btu/hour and firing wood with coal, oil, or natural gas will be installed in the next 5 years is not in line with the current pace of installation. They suggested that a better estimate would appear to be 15 new units with a heat input capacity of 10×10^9 Btu/hour, or about one-half of this projection.

Response: The purpose of the analysis was to assess the potential impacts associated with alternative standards on mixed fuel-fired steam generating units firing mixtures of nonsulfur-bearing fuels with coal or oil. Thus, the analysis includes mixed fuel-fired steam generating units firing other fuels, such as municipal solid waste, for example, as well as wood. Therefore, while the projection

of 35 new mixed fuel-fired steam generating units may not be exact if only units firing wood with coal or oil are considered, the addition of units firing municipal solid waste, combined with expected growth in this source category, resulted in this figure being selected for purposes of analysis.

7. Comment: Two commenters (IV-D-5, IV-D-58) said the selection of coal type for meeting a 516 ng/J (1.2 lb/million Btu) standard is not correct in Table 16 of the mixed fuel-fired steam generating unit report for the 117 MW (400 million Btu/hour) unit cases. They asserted that this error affects the annualized costs and emissions, and thus the cost effectiveness numbers, and should be revised. In addition, the commenters said the selection of oil type in Table 18 for units firing an 80 percent oil/20 percent wood mixture and meeting a 344 ng/J (0.8 lb/million Btu) emission limit appears to be incorrect.

Response: The costs cited in Table 16 of the subject report are based on the coals specified in Table 15. The commenters are correct in pointing out that some of the coals selected for meeting a 516 ng/J (1.2 lb/million Btu) standard are in error. This applies to the 50 percent coal/50 percent nonsulfur-bearing fuel mixtures in Regions I and IV and the 80 percent coal/20 percent nonsulfur-bearing fuel mixtures in Regions I, IV, and X. In the case of the 344 ng/J (0.8 lb/million Btu) standard for mixed fuel-fired units firing oil, the oil type specified for the 80 percent oil/20 percent nonsulfur-bearing fuel was also in error.

Each of these oversights has been addressed and corrected in a subsequent analysis performed to evaluate the impacts of new fuel prices on the previous analysis. The revised analyses are discussed in the memoranda entitled "Impact of New Fuel Prices on the Cost and Cost Effectiveness of SO₂ Emission Control of Mixed Fuel-Fired Steam Generating Units" and "Impact of New Fuel Prices on the National Impacts Analysis for Mixed Fuel-fired Steam Generating Units."

8. Comment: Several commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-D-58, IV-D-62, IV-D-65, IV-D-66, IV-D-74, IV-D-84, IV-F-1.7, IV-F-1.14) stated that the impacts of a percent reduction requirement on mixed fuel-fired steam generating units should be further analyzed. They noted that combination units have advantages such as lower SO₂ emissions, conservation of fossil fuels, and disposal of waste materials that should not be discouraged. Also, they said, mixed fuel-fired steam generating units will account for, at most, only 0.06 million Mg (0.07 million tons) SO₂/year of a nationwide total of 23 million Mg (25 million tons) SO₂/year. They expressed concern that imposing a percentage reduction on these units could provide a disincentive to some companies considering installing them.

Response: The impacts of alternative SO₂ control options on mixed fuel-fired steam generating units were reanalyzed in light of recent declines in oil and gas prices. New fuel prices were developed for coal, oil, and natural gas and used to assess the impacts of the standards on mixed fuel-fired steam generating units. The impacts associated with this updated analysis are generally lower than those in the original analysis, and are considered reasonable. The requirements associated with the final standards are not

expected to discourage future installations of mixed fuel-fired steam generating units. The costs associated with SO₂ control are only a small proportion of total steam generating unit costs, and the advantage of firing wastes generated on-site as fuel will generally help offset any increased costs associated with SO₂ control. In addition, as discussed above, the exemption from the percent reduction requirement included in the final standards for steam generating units firing coal or oil at 30 percent or less of their total annual capacity will serve as an incentive for these units to fire more waste fuels and less coal or oil.

9. Comment: One commenter (IV-D-20) said that the standard listed in 40 CFR 60.45b(f) appears to apply to the combustion of oil "only" and does not clarify whether it applies to oil fired in combination with other fuels. Units fired with oil in combination with natural gas, waste wood, etc., should be provided a similar exemption as that available for coal firing under 60.42b(c). Another commenter (IV-D-92) requested clarification on 60.42b(c)(1). The commenter asked whether subparagraph (ii) applies only to units that burn coal in combination with other fuels or whether it may also apply to situations in which oil or natural gas is burned in combination with other fuels such as municipal solid waste where such waste constitutes 10 percent or more of the annual capacity utilized. The commenter said if 60.42b(c)(1) does not apply to other situations where oil or gas is co-fired with other nonfossil fuels, why is an exemption reserved for coal since coal emits more SO₂ than oil or natural gas?

Response: As discussed earlier, the final standards provide an exemption from the percent reduction requirement for steam generating units which obtain 30 percent or less of their

annual maximum heat input capacity from the combustion of oil or coal (or a combination of oil and coal). This provision applies regardless of whether the coal or oil is fired alone or in combination with natural gas or nonfossil fuels.

2.13 STANDARD FOR COGENERATION UNITS

1. Comment: Several commenters expressed the opinion that emission credits should be allowed for cogeneration systems. Some (IV-D-26, IV-D-38, IV-D-60, IV-D-73, IV-D-79, IV-D-84) argued that a cogeneration system which produces both steam and electricity from one heat source will result in lower emissions than separate units for each purpose. They also felt that if full credit for this difference is not considered cost effective, the Agency should at least look at the cost effectiveness of some fraction of the difference in emissions being applied as a credit.

Another commenter (IV-D-28) said the analysis of cogeneration contained in the proposal ignored the fact that processes which are more efficient use less of natural resources and emit less waste to the environment. The commenter felt that these benefits should be encouraged through the allowance of credits. Also, the commenter said, the marginal cost effectiveness for the additional SO₂ reduction that results from denying these credits to cogeneration units ranges from \$330-\$550/Mg (\$300-\$500/ton) for FGD-based systems and from \$1,650-\$3,300/Mg (\$1,500-\$3,000/ton) for compliance fuel-based systems. The commenter said credits also encourage energy efficiency and offer nonSO₂ environmental benefits by requiring less

resource extraction, transportation, etc., and stated that these benefits and improved cost effectiveness should be encouraged.

Response: As discussed above for mixed fuel-fired steam generating units, emission credits would permit SO₂ emissions from a cogeneration steam generating unit to increase to the level that would have existed if a conventional, rather than a cogeneration, steam generating unit had been installed. As a result, emission credits effectively reduce the environmental benefits, in terms of reduced SO₂ emissions, associated with cogeneration.

The merits of emission credits for cogeneration systems were thoroughly examined and discussed in the "Summary of Regulatory Analysis," "An Analysis of the Costs and Cost Effectiveness of Allowing SO₂ Emission Credits for Cogeneration Systems," and "Impact of New Fuel Prices on SO₂ Emission Credits for Cogeneration Systems and Mixed Fuel-Fired Steam Generating Units." To assess the merits of emission credits, the costs, SO₂ emissions, and cost effectiveness of SO₂ control were analyzed with and without an emission credit. This analysis concluded that granting an emission credit for cogeneration steam generating units results in very small reductions in costs while allowing significant increases in SO₂ emissions. Therefore, the incremental cost effectiveness of the additional emission reductions achieved by not providing emission credits for cogeneration steam generating units is low, generally in the range of \$220-\$660/Mg (\$200-\$600/ton). Similar cost effectiveness values exist relative to not providing partial emission credits. These costs are considered reasonable in view of the significant additional emission reductions

achieved by not providing emission credits. Consequently, the final standards do not include provisions for emission credits for cogeneration systems.

The absence of emission credits for cogeneration systems is not expected to discourage their use. The non-SO₂ environmental benefits listed by the commenters, such as lower fuel costs resulting from greater energy efficiency, should still provide incentive for the use of this technology.

2. Comment: One commenter (IV-D-44) said that because they often do not produce other plant wastes, FGD system waste disposal costs could be a significant burden for cogeneration systems.

Response: Even those cogeneration systems which are not part of a manufacturing plant that produces plant wastes (such as those used solely for "third party" generation of steam and electricity for sale) will produce some waste from operation of the steam generating unit itself. For example, firing coal produces an ash that must be disposed of regardless of other regulatory requirements. In addition, the steam generating unit will produce waste from steam generating unit blowdown and other routine steam generating unit operation and maintenance procedures.

As discussed previously (see Section 2.10.1), the standard is not "based" on the use of any particular SO₂ control technology. Therefore, where disposal of waste associated with a "wet" FGD system, for example, would be burdensome, other technologies (such as lime spray drying or fluidized bed combustion) could be selected to change the nature of the waste produced. In addition, where an individual

confronted with the standards may view the burden associated with disposal of any wastes as excessive, the use of alternative fuels, such as natural gas, would substantially reduce or eliminate the need for waste disposal.

3. Comment: One commenter (IV-D-44) asserted that if the proposed standards are promulgated, the economics of cogeneration projects will be severely affected. The commenter stated that because the prices for steam and electricity are determined by factors that will not be significantly affected by the regulation, the additional operating costs incurred cannot be "passed through" to the steam purchaser. Therefore, the commenter said, the added costs of complying with a percent reduction requirement would significantly reduce the number of viable cogeneration projects. The commenter requested that cogeneration facilities be exempted from the standards or less stringent standards adopted for these facilities.

Response: The final standards will increase the project costs of coal- and oil-fired cogeneration steam generating units. This could preclude some smaller, less profitable cogeneration projects. However, most coal- and oil-fired cogeneration steam generating units covered by the standards will not be severely affected. For example, a cost analysis of the impact of standards on a typical coal-fired cogeneration steam generating unit showed that a percent reduction requirement increased the total annualized steam generating unit costs by about 11 percent. This can be compared to the results of the "Survey of New Industrial Boiler Projects," which indicate that more than 80 percent of the cogeneration projects completed in 1981 through 1984 would have gone forward as designed even if costs increased by 10 percent.

In addition, more than 60 percent of the cogeneration projects would have gone forward as designed if costs increased by as much as 20 percent.

To put the impact of the standards on cogeneration projects into perspective, however, it must be realized that not all cogeneration projects will be affected by the final standards. In fact, given current fuel prices, most new cogeneration projects are expected to be based on firing natural gas (both natural gas-fired turbines and natural gas-fired boilers with steam turbines) or municipal solid waste. Cogeneration projects firing these fuels are not affected in any way by the SO₂ standards. Thus, the standards will have no impact on most new cogeneration projects.

Finally, another factor to consider is that new coal-fired cogeneration steam generating units compete with new coal-fired electric utility steam generating units, which are subject to percent reduction requirements. Application of percent reduction to coal-fired cogeneration steam generating units, therefore, is a "neutral" position which treats both utility steam generating units and industrial-commercial-institutional cogeneration steam generating units in a similar manner. Consequently, the final standards include no special provisions for cogeneration steam generating units. They are treated just like any other industrial-commercial-institutional steam generating unit.

4. Comment: Two commenters (IV-D-44, IV-F-1.17) said the standards would make many cogeneration projects uneconomical by increasing the capital costs of a standard 55 MW cogeneration facility

by about \$5.3 million. In addition, the commenter said that operating costs, disposal costs, and costs due to decreased steam generating unit availability would be significantly higher than those estimated in the proposal. Increased annual costs of a 90 percent reduction requirement were estimated by the commenter at \$3.7 million. The cost effectiveness of SO₂ removal would be over \$1,760/Mg (\$1,600/ton) compared to the proposal estimates of \$430 to \$475/Mg (\$390 to \$430/ton). This, the commenters said, would put builders of cogeneration systems out of business.

Response: The Agency reviewed its cost estimates for compliance with a percent reduction standard on a 55 MW cogeneration facility and found them to be consistent with those cited by the commenter. Similarly, the Agency's estimates of cost effectiveness of percent reduction are similar to those cited by the commenter. Further, these costs are similar to those imposed on a conventional coal- or oil-fired steam generating unit of the same size and are not believed to impose an unreasonable burden on cogeneration facilities. The commenter's citation of \$430 to \$475/Mg (\$390 to \$430/ton) is a national average, and is not intended to imply that higher cost effectiveness values for individual units are reasonable or unreasonable.

In summary, the impact of the final standards on cogeneration facilities was examined in some detail and is considered consistent and reasonable for cogeneration, as well as conventional, steam generating units. Also, as noted in the previous response, the final standards for industrial-commercial-institutional cogeneration systems are consistent with those for electric utility steam generating units.

5. Comment: One commenter (IV-D-44) said that in conformance with national energy policy goals, the Powerplant and Industrial Fuel Use Act of 1978 stated that cogeneration facilities must be constructed with "the capability to use coal or any other alternate fuel as a primary energy source." Thus, the commenter said, it is not reasonable to assume that these facilities will be able to switch to natural gas. The commenter claimed that the effect of EPA's fuel switching assumption is to underestimate the costs of compliance for cogeneration systems.

Response: Regulations under the Fuel Use Act, which prohibited the use of natural gas in most new industrial-commercial-institutional steam generating units, were repealed by P.L. 100-42, signed on May 22, 1987. Under the new law, conventional steam generating units and cogeneration systems which sell less than 50 percent of the total electrical production to a utility are exempted from the Fuel Use Act's natural gas use restrictions. Cogeneration units operating in excess of 3500 hours per year and selling in excess of 50 percent of their electrical output to a utility must be designed with the capability to burn coal or coal-derived fuels, but can obtain an exemption to burn natural gas if using coal would impose an economic hardship or penalty. Because a facility switching from coal to natural gas in response to the standards would be doing so to avoid the higher costs associated with firing coal, obtaining such an exemption should be straightforward.

2.14 STANDARD FOR EMERGING TECHNOLOGIES

1. Comment: A number of commenters (IV-D-23, IV-D-26, IV-D-30, IV-D-40, IV-D-43, IV-D-50, IV-D-52, IV-D-53, IV-D-58, IV-D-62, IV-D-66, IV-D-73, IV-D-74, IV-D-75, IV-D-81, IV-D-84,

IV-D-85, IV-F-1.1, IV-F-1.8, IV-F-1.16) said fluidized bed boilers are only beginning to show promise for low cost pollution control in some energy intensive industries. The commenters felt that this technology should be considered an emerging, rather than demonstrated, technology.

Response: As discussed previously (see Section 2.8.2), fluidized bed combustion is considered a demonstrated technology capable of achieving 90 percent reduction on a continuous basis at high reliability levels.

2. Comment: One commenter (IV-D-43) said that fluidized bed steam generating units firing culm (anthracite mining waste) and gob (bituminous coal mining waste) should be considered an emerging technology. According to the commenter, this technology is different from that used to burn conventional fuels.

Response: As discussed above, fluidized bed combustion is considered a demonstrated, rather than emerging, technology. As also discussed earlier, however, concerns remain about the economic viability of using this technology to achieve a 90 percent reduction in SO_2 emissions when firing culm or other types of coal refuse. As a result, a less stringent percent reduction requirement has been established for FBC units firing coal refuse.

3. Comment: One commenter (IV-D-40) said that, by definition, an emerging technology has not been "adequately demonstrated." Therefore, the commenter said, a standard for emerging technology cannot be set under Section 111. Others (IV-D-6, IV-D-7, IV-D-28, IV-D-38, IV-D-40, IV-D-50, IV-D-52, IV-D-75) agreed, saying new technologies lack sufficient

operating data upon which to base NSPS. Several commenters (IV-D-6, IV-D-26, IV-D-28, IV-D-40, IV-D-50, IV-D-52, IV-D-72) added that Federal standards regulating emissions from steam generating units using emerging technologies should not be proposed until valid test data from a representative group of such installations across U.S. industry have been tabulated and reviewed to determine the appropriate emission levels for such technologies. They said premature proposal of standards would inhibit and retard development and commercial demonstration of these technologies. Another commenter (IV-D-99) stated that the emerging technology provision is beneficial only to technologies having substantial near-term promise of exceeding 90 percent SO₂ control at a relatively low cost. This, the commenter said, would terminate development and commercialization of many technologies capable of substantial, cost effective SO₂ control, but less than 90 percent reduction. One commenter (IV-D-76) said no quantitative or cost effectiveness analysis was provided for the proposal to allow emerging technologies to achieve a less stringent 50 percent reduction requirement.

Response: In the absence of provisions for emerging technologies, all sources would have to achieve performance levels that conform with best technical system of continuous emission reduction. The commenters do not dispute that EPA has authority to make provisions designed to encourage the emergence of new technology. That being the case, there can be no question that EPA has the authority to define parameters conducive to that goal.

As discussed at proposal and also mentioned by the commenters, however, standards requiring a high level of performance, such as 90 percent reduction, could act to discourage continued development of some new technologies. Owners and operators of new steam generating units could simply view the risks of using a new and untried emission control technology to achieve a 90 percent reduction in emissions as too great. Thus, to encourage the continued development of emission control technologies that show promise of achieving levels of performance comparable to those of existing technologies, special provisions are included in the standards to accommodate and, it is hoped, foster the continued development of new technologies.

These provisions do not reflect the perceived performance capability of any specific new or emerging technologies. As discussed at proposal, these provisions reflect a reasoned judgment of an appropriate balance between a level of performance which is low enough to significantly reduce the risks associated with use of a new technology, but also high enough to ensure that with continued development the technology appears to have the potential to achieve performance levels comparable to those achieved by existing technologies, as well as ensuring that the increased emissions resulting from use of the new technology are minimized.

A standard requiring a 50 percent reduction in SO₂ emissions, but also limiting emissions to 172 and 258 ng/J (0.4 and 0.6 lb/million Btu) heat input for oil and coal, respectively, appears to strike this balance. A minimal percent reduction requirement of 50 percent should effectively eliminate the risk of failure for any technology

which has the potential to reduce emissions by 90 percent. It is difficult to conceive of a new control technology that would be incapable of achieving at least a 50 percent reduction in SO₂ emissions during development, and still have potential for achieving 90 percent reduction when development is completed.

When combined with the emission limits stated above, this standard minimizes SO₂ emissions by limiting these emissions to 50 percent or less of those resulting from the use of low sulfur coal or oil. The emission limits will encourage the further development of these emerging technologies by requiring higher percent reductions when firing higher sulfur fuels. Thus, the final standards retain the special provisions, as they were proposed, for emerging technologies.

4. Comment: A number of commenters (IV-D-23, IV-D-26, IV-D-28, IV-D-30, IV-D-38, IV-D-45, IV-D-50, IV-D-51, IV-D-52, IV-D-53, IV-D-58, IV-D-62, IV-D-66, IV-D-73, IV-D-74, IV-D-75, IV-D-80, IV-D-84, IV-D-85, IV-D-88, IV-F-1.16) expressed the opinion that requiring emerging technologies to meet a maximum emission cap of 258 ng/J (0.6 lb/million Btu) is overly restrictive, arbitrary and will operate as a disincentive for industries wishing to pursue the installation of promising but unproven technology. They said the use of emerging technology should not be discouraged by regulations or otherwise. The commenters asserted that this emission cap should be raised to 516 ng/J (1.2 lb/million Btu) for emerging technologies. This, they said, is consistent with the cap for adequately demonstrated technology and would allow affected sources to burn a wider range of coals, thereby generating a better data base for

future decision making. One commenter (IV-D-52) added that the requirement that facilities using emerging technologies meet an emission limit of 258 ng/J (0.6 lb/million Btu) heat input is unnecessary as a safeguard against the failure of the new technology to meet the required degree of reduction. The commenter said any potential problems with the emerging technologies can be addressed and resolved through the use of the current permitting procedures implemented by the States.

Response: As discussed above and in the preamble to the proposed standards, limiting the emerging technology provision to the use of low sulfur fuels will minimize any increase in SO₂ emissions as a result of the use of an emerging technology. For coal-fired steam generating units, an emission limit of 258 ng/J (0.6 lb/million Btu) essentially requires the use of coal with potential SO₂ emissions of 516 ng/J (1.2 lb/million Btu) or less if the minimum 50 percent reduction is being achieved. However, to the extent that an emerging technology achieves emission reductions greater than 50 percent, coal with higher sulfur contents can be used to comply with the emission limit. Therefore, this "emission cap" provides a further incentive for the continued development of emerging technologies. The purpose of this emission limit is not to provide a "safeguard" against the failure of emerging technologies to achieve a 50 percent reduction in emissions, but rather to minimize total emissions from technologies achieving 50 percent reduction. Any technology subject to the emerging technology provisions must achieve at least a 50 percent reduction in emissions, or it will be subject to the same enforcement requirements and/or penalties as conventional demonstrated technologies.

5. Comment: One commenter (IV-D-64) said the proposed standards for emerging technologies are too lenient, because steam generating units using "emerging technologies" would be allowed to emit more than facilities using conventional technologies due to the lower percent reduction requirement. The commenter said the maximum emission limit should be no greater than the equivalent of a 90 percent reduction from the average sulfur content of coal used in industrial steam generating units.

Response: It is possible that sources subject to the emerging technology provisions will have higher SO₂ emission rates than sources using conventional demonstrated SO₂ control technologies. The emission limits established for emerging technologies serve to minimize this difference in emissions by essentially restricting the use of these technologies to sources firing low sulfur fuels. The imposition of more stringent emission limits could provide too great a disincentive to the use of emerging technologies, contrary to the intent of establishing an emerging technology provision.

6. Comment: Several commenters (IV-D-26, IV-D-52, IV-D-75, IV-D-80, IV-F-1.12) said the proposal would discourage the development of inexpensive innovative technologies because it would require high-risk investment, since any technology would have to meet both highly restrictive percentage reduction figures (50 percent) and an emission rate of 258 ng/J (0.6 lb/million Btu). According to the commenters, it would also reduce the capital available for continued research and commercial development since a major portion of a company's finite dollars would have to be spent on FGD systems and/or backup systems to ensure immediate and continued compliance with the standards.

Response: Any SO₂ control technology with the potential of achieving 90 percent emission reductions in the future should be able to meet a 50 percent reduction requirement at initial application. This is not considered overly restrictive since the aim of the emerging technology provision is to foster development of SO₂ control technologies with promise of achieving "demonstrated technology" status (i.e., 90 percent reduction). As discussed previously, the emission limits for emerging technologies are also considered reasonable in light of the purpose of the emerging technology provision.

7. Comment: One commenter (IV-D-3) suggested that the Agency should consider how it plans to limit the emerging technology provision to: (1) new technologies or processes which are unique relative to demonstrated technologies rather than simply modified versions of currently demonstrated technologies, and (2) those which are likely to be able to meet 90 percent removal after a reasonable demonstration and development time.

Response: As in the proposed standards, the final standards include definitions of demonstrated technologies. In some cases, these definitions have been revised in response to the concerns expressed by the commenter. Technologies considered as nothing more than slightly modified versions of existing demonstrated technologies will not be viewed as emerging technologies by the Agency.

As with all new source performance standards, steam generating units subject to the final standards must notify the Agency within 30 days of the date of commencement of construction of the affected facility. If the owner or operator of the steam generating unit plans to use an

generating unit plans to use an emerging technology, and thereby operate under a 50 percent reduction requirement, a full and complete description of this technology must be submitted to the Agency along with a discussion of how or why this technology does not meet any of the definitions of demonstrated technologies. Technologies not considered demonstrated by the Agency will be designated as emerging technologies, and the steam generating unit owner or operator will be so notified. If the steam generating unit commences operation with the technology and fails to comply with the 50 percent reduction requirement and the established emission limits for emerging technologies, it will be subject to enforcement action by the Agency. In addition, to ensure and maintain consistent enforcement of the special provisions for emerging technologies, these provisions will not be delegated to States.

The emerging technology provision will be reviewed regularly during the course of the review process associated with all NSPS. As appropriate, the percent reduction requirements will be revised upward in light of additional performance data available at that time for various emerging technologies. As a result of these reviews, emerging control technologies that do not demonstrate improvements in performance capabilities, or show no promise of achieving emission reductions greater than 50 percent, will no longer be considered emerging technologies and all subsequent installations would be subjected to the same requirements as those included in the standards for conventional demonstrated control technologies.

9. Comment: Two commenters (IV-D-26, IV-D-73) felt that the procedures in 60.49(b)(4) for establishing controls as emerging technologies are too complex, time consuming, and

discretionary. They said the procedure should be more streamlined and straightforward in the steps for gaining approval as an emerging technology.

Response: The procedures for establishing controls as emerging technologies consist of submitting a description of the technology to the Administrator for review and approval. This is not considered to be an unreasonable requirement, given the significant benefits associated with qualifying as an emerging technology.

10. Comment: Several commenters (IV-D-26, IV-D-28, IV-D-30, IV-D-42, IV-D-50, IV-D-53, IV-D-73, IV-F-1.16) said disallowance of credit for precombustion cleaning of fuel toward the percent reduction requirement for emerging technologies is inappropriate and counter to the Agency's past philosophy of preferring the cleanup of fuels prior to combustion, rather than post-combustion cleanup. Another (IV-D-52) felt that fuel precleaning should be included among the emerging technologies, consistent with the Agency's previous position of encouraging fuel precleaning.

Response: While the allowance of full credit for fuel pretreatment toward the 90 percent reduction requirement is appropriate and is allowed in the final standards, giving credit for fuel pretreatment toward the 50 percent reduction requirement for emerging technologies is inappropriate for several reasons. First, the primary objective of the 50 percent reduction requirement is to stimulate and encourage the development and use of emerging SO₂ control technologies which show promise of achieving significant emission reductions in the future. Any emerging technology that is unable to reduce emissions by 50 percent without the

use of fuel pretreatment credits is unlikely to have any potential for achieving SO₂ removal levels of 90 percent in the future.

Second, allowance of fuel pretreatment credits toward the 50 percent reduction requirement would give a disproportionately larger benefit to emerging technologies than to technologies subject to the 90 percent reduction requirement. For example, a steam generating unit firing coal with potential SO₂ emissions of 4,300 ng/J (10 lb/million Btu) and subject to a 90 percent reduction requirement would be required to reduce emissions to 430 ng/J (1 lb/million Btu). Allowance of a 30 percent fuel pretreatment credit would reduce the effective sulfur content to 3,010 ng/J (7 lb/million Btu). In order to achieve an emission level of 430 ng/J (1 lb/million Btu), an 85.7 percent reduction in SO₂ emissions is still required.

However, a steam generating unit firing this same coal and subject to the 50 percent reduction requirement would be required to reduce emissions to only 2,150 ng/J (5 lb/million Btu). Allowance of a 30 percent fuel pretreatment credit would reduce the effective sulfur content to 3,010 ng/J (7 lb/million Btu), requiring only a 28 percent reduction in SO₂ emissions to be achieved by the control device. This is clearly contrary to the intended purpose of encouraging the development of SO₂ control technologies capable of achieving a 90 percent reduction in emissions.

The final standard, therefore, does not allow fuel pretreatment to be credited against the percent reduction requirement for emerging technologies. The final standard has, however, been amended to allow this fuel pretreatment

credit if all of the required 50 percent reduction is achieved by the fuel pretreatment technology. This will serve to encourage the development of fuel pretreatment technologies that show promise of achieving significant (i.e., 90 percent) SO₂ reductions.

11. Comment: One commenter (IV-D-85) said that lime spray drying should be considered an emerging technology for oil-fired steam generating units.

Response: As discussed above in Section 2.8, lime spray drying is considered to be capable of achieving a 90 percent reduction in SO₂ emissions from oil-fired steam generating units, and is therefore considered a "demonstrated" technology for this application.

12. Comment: Two commenters (IV-D-11, IV-F-1.5) requested that natural gas re-burn/sorbent injection be considered a new SO₂ control technology subject to the 50 percent reduction requirement.

Response: If natural gas re-burn/sorbent injection is capable of achieving at least a 50 percent reduction in SO₂ emissions from coal- or oil-fired steam generating units, it would qualify as an emerging technology under the final standards.

13. Comment: One commenter (IV-D-42) said the municipal waste handling techniques of source separation and waste processing and recycling should be considered emerging technologies subject to the 50 percent reduction requirement.

Response: Municipal waste is not a regulated fuel under the standards and is therefore not subject to a percent reduction requirement.

2.15 MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS

2.15.1 Continuous Emission Monitoring Systems

1. Comment: One commenter (IV-D-38) said the standard should allow for alternatives to continuous emission monitoring systems (CEMS), such as monitoring fuel sulfur content. The commenter asserted that CEMS are extremely difficult to operate and are unreliable. Another commenter (IV-D-74) said sources which are exempt from the percent reduction requirement should be allowed to monitor fuel sulfur content to demonstrate compliance with the standards.

Response: The standard does allow alternatives to CEMS. As mentioned previously (see Section 2.7.5), steam generating units subject to a percent reduction requirement can use inlet fuel sampling and analysis in place of inlet CEMS and Method 6B stack testing can be used in place of the outlet CEMS. For steam generating units exempt from the percent reduction requirement, where only one sampling device is required, either fuel sampling or Method 6B may be used in place of a CEMS.

2. Comment: One commenter (IV-D-62) claimed that it is not reasonable to apply the requirements for continuous emission monitoring prior to control equipment, since emissions prior to the control equipment do not have an impact on the environment or on public health or welfare. The commenter said it is

only actual emissions entering the atmosphere which may have an effect on public health and welfare, and which may have other environmental effects.

Response: In order to determine whether a percent reduction is being achieved by the SO₂ control device, it is necessary to know what the potential emissions of the flue gas were before it passed through the control device. Therefore, some type of inlet monitoring is necessary. This is commonly achieved with a CEMS, but can also be achieved by fuel sampling and analysis.

3. Comment: Four commenters (IV-D-28, IV-D-56, IV-D-81, IV-F-1.1) said the CEMS requirements, which are basically the same as those for utility steam generating units, are unreasonable for industrial-commercial-institutional steam generating units. They said the provision that units using low sulfur fuels still be required to monitor emissions continuously results in monitoring costs that exceed pollution control costs in some cases, and creates an artificial bias against the use of low sulfur coals. The commenters suggested that provisions similar to those in the current NSPS providing for alternatives to CEMS would markedly improve the cost effectiveness of coal cleaning and low sulfur fuel use without affecting the cost effectiveness of FGD. They asserted that for a monitoring system to exceed the cost of a control system by several fold is contrary to policy implicit in existing regulations.

Response: As discussed above, the final standard does allow alternatives to CEMS, such as inlet fuel sampling in lieu of an inlet CEMS. Steam generating units obtaining 30 percent or less of their maximum heat input capacity on an annual

basis from coal or oil may monitor emissions using as-fired fuel sampling and analysis or Method 6B, as provided in Method 19.

The annualized costs for emissions monitoring (assuming both an inlet and outlet SO₂ monitor and diluent monitor) were estimated in the "SO₂ Cost Report" to be approximately \$100,000/year, compared to total annualized emission control costs of \$900,000/year for a typical 44 MW (150 million Btu/hour) steam generating unit firing low sulfur coal. This represents only about 10 percent of total SO₂ control costs.

4. Comment: Several commenters questioned the performance and reliability of CEMS. Two (IV-D-81, IV-F-1.1) asserted that the reliability of CEMS has not been proven, especially in the acidic atmosphere found in FGD systems. Others (IV-D-22, IV-D-26, IV-D-30, IV-D-50, IV-D-53, IV-D-72, IV-D-78, IV-F-1.6) felt that the need for CEMS should be eliminated due to high maintenance requirements, shortages of instrument technicians, high capital costs, and the consequent likelihood of unavailability. They said that small companies with limited staffing will be hard pressed to deal with the monitoring and reporting requirements.

Response: The reliability of SO₂ and diluent CEMS were extensively studied during the development of Subparts D, Da, and J and Appendix F of 40 CFR Part 60. The gas streams found at these sources are similar to those found at industrial-commercial-institutional steam generating units. These studies found CEMS to be reliable and capable of meeting the minimum data availability requirements described in this standard.

In addition, the costs associated with the monitoring and reporting requirements were examined. This included the costs associated with the initial performance test and performance demonstration of the CEMS, as well as operation and quality assurance procedures, data collection, and report preparation. For most facilities, the costs would be less than \$20,000/year after the first year. These costs are considered reasonable. If, in an individual situation, a steam generating unit operator perceives the CEMS requirements as too burdensome, alternative monitoring procedures may be used, as described above.

5. Comment: One commenter (IV-D-62) said that it is neither reasonable nor necessary to require continuous emission reduction monitoring and reporting, if an effort is made to set and enforce reasonable emission limits.

Response: The final standards are based on the "best" technological system of continuous SO₂ emission reduction, as required by Section 111 of the Clean Air Act. This "best demonstrated technology" is the use of FGD to control SO₂ emissions. In order to determine that a percentage reduction is being achieved by the control device, continuous emission monitoring at both the inlet and outlet to the control device is necessary. As discussed above, the costs associated with all monitoring and reporting requirements in the final regulation were assessed and are considered reasonable.

2.15.2 Averaging Time

1. Comment: Several commenters (IV-D-23, IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-84) felt that the proposed 30-day rolling average compliance period is unreasonably short. They

suggested that compliance be determined on at least a quarterly or 90-day basis to provide operational flexibility. The commenters added that the 30-day average does not ensure that a well designed and operated source will comply with the rule despite its best efforts. They contended it is a violation of Section 111 to promulgate a standard that allows a well operated facility to violate the standards.

Response: As discussed in the "Summary of Regulatory Analysis," various averaging times were considered. The primary purpose of establishing an averaging time for compliance purposes is to minimize the effect of variability in fuel sulfur content and short-term performance of control devices on compliance with the standards. The longer the period selected for averaging SO₂ emissions data, the lower the variability exhibited by the data and the more realistically it reflects the long-term or average performance of the system. However, in terms of enforcing compliance with the standards, this averaging period must also be short enough to permit timely enforcement of a standard once a source begins operation. An averaging period of 30 days is considered long enough to yield data representative of long-term performance, while also being short enough to allow timely enforcement of the standards. In addition, use of a 30-day rolling average (as opposed to a discrete average) allows enforcement of the standard on a daily basis.

Based on the assessment of demonstrated performance levels for the various SO₂ control systems discussed in the "Summary of Regulatory Analysis," a properly designed, well

operated, and properly maintained control system will be able to comply consistently with the standards on a 30-day rolling average basis.

2. Comment: Two commenters (IV-D-1, IV-D-20) said the requirement to calculate rolling 30-day average SO₂ emissions using only steam generating unit operating days rather than consecutive calendar days makes comparison with other data (e.g., ambient) difficult if not impossible. Three commenters (IV-D-1, IV-D-20, IV-D-86) suggested that a daily average emission limit should be added to the 30-day rolling average emission limit to prevent steam generating unit owners or operators from burning very high sulfur fuel at a very high rate one day, then burning very low sulfur fuel another day to compensate.

Response: The calculation procedures as proposed are considered appropriate. Some industrial steam generating units may experience sporadic usage patterns that result in the steam generating units only being operated for a few days in a calendar month. Using 30 consecutive calendar days to determine average emissions would permit steam generating unit operators to "trade off" emissions during those days when the steam generating unit was operating against days when no emissions occurred because the steam generating unit did not operate. This approach would effectively defeat the objective of the standards -- i.e., to minimize emissions from combustion of fuels in steam generating units. Allowing a "credit" for periods of time when the steam generating unit is not operated would reduce the reduction in emissions necessary from combustion of fuels when the steam generating unit is operated.

The CEMS requirements under Subpart Db are associated with Subpart Db technical SO₂ control requirements. If other averaging times are judged necessary under SIP requirements or other environmental programs, the operating permit issued under PSD determinations can require CEMS data to be provided for that site-specific averaging time.

3. Comment: One commenter (IV-D-38) said the rules should be reviewed to allow for block rather than rolling averages as is allowed for utility sources. The commenter asserted that there is no reason for this standard to be more stringent than the utility standard.

Response: The utility standard (Subpart Da) requires compliance determination on a 30-day rolling average basis and, thus, is the same as this standard. As mentioned above, the purpose of a rolling average is to provide compliance data on a continuous, daily basis. A block average would not allow this daily record, which is important in enforcing the standards to ensure that compliance is being achieved and maintained on a continuous basis.

4. Comment: One commenter (IV-D-32) felt that the emission monitoring requirements should be simplified, and suggested that a 30-day composite sampling program be instituted in place of rolling averages.

Response: Compositing fuel samples collected over a 30-day period for analysis would not provide daily compliance data, which is necessary for enforcement. A 30-day composite would effectively convert the standard from a rolling average to a block average. As discussed above, a block average would preclude the ability of enforcement personnel to enforce the

standard on a continuous, daily basis. Thus, a 30-day composite sampling program would unnecessarily reduce the enforceability of the standards.

2.15.3 Data Availability Requirements

1. Comment: Two commenters (IV-D-1, IV-D-86) stated that if enforcement actions are taken for failure to meet minimum data availability requirements, the estimation procedures of Method 19 would be unnecessary as sources would maintain the CEMS so as to obtain the minimum amount of data in order to avoid penalties.

Response: The minimum data availability requirements are directly enforceable, and failure to meet them is considered a violation. However, this does not preclude the need to calculate average percent reduction and emission values for the period. The data estimation procedures in Method 19 are provided to enable a judgment to be made with a measure of confidence using available data when the minimum amount of data is not obtained.

2. Comment: One commenter (IV-D-13) noted that Section 60.47b(d) requires at least two data points to calculate each 1-hour average, while 60.13(h) of the General Provisions requires four or more equally spaced data points over each 1-hour period. For the sake of consistency, the commenter said, the Subpart should agree with the General Provisions unless substantial reasons can be given for doing otherwise. Two other commenters (IV-D-1, IV-D-86) suggested that the minimum amount of data necessary for a valid hourly average should be specified as a percent rather than the proposed "two points." They said the proposal would allow the use of

readings recorded during the first 2 minutes of the hour to be used to calculate the average for the hour. The commenters pointed out that sources in Pennsylvania must collect 75 percent valid data for a valid hourly average.

Response: The requirements in 60.13(h) are minimum CEMS design criteria; those in 60.47b are minimum data capture or CEMS performance criteria. These minimum performance criteria are sufficient to indicate that the CEMS is being properly operated and maintained. Facilities are still required to collect all data; the "2 points" requirement is a minimum standard that must be met. There is no need for this to be the same as the design criteria in the General Provisions.

It is true that, as proposed, the regulation allowed 2 minutes of data to be used to represent an hour average. This was judged to be inappropriate, and the monitoring requirements have been clarified in the final standards. The final standards require at least 30 minutes of continuous operation in order to obtain a valid 1-hour average. In addition, one of the two required data points must be obtained during each of the two 15-minute periods of operation.

3. Comment: Two commenters (IV-D-1, IV-D-86) said the use of the proposed "75 percent of operating hours" criterion would allow a single hourly average to represent the emissions for the entire day if the unit were operated only during that hour for the day. They felt that some criteria based on total hours rather than operating hours should be used so that short-term data would not be used to determine compliance with long-term averages. Another commenter (IV-D-64) said that because the proposed regulation requires

emissions data for only 75 percent of the operating hours in 22 of 30 days, only 65 percent of the total operating time for the facility must be included. The commenter said the monitoring requirements should be amended to ensure that complete and accurate data on emissions are generated, and to not reward operators who do not operate their monitors properly.

Response: The requirement for "... a minimum of 75 percent of the operating hours in at least 22 of 30 successive steam generating unit operating days" is solely related to CEMS performance criteria and is not related to procedures for calculating 30-day average emission rates. The 30-day average emission rate which is used to determine compliance with the standard is calculated as the average of all valid hourly emissions data in the past 30 steam generating unit operating days. All hourly emissions data are given equal weight; therefore, it does not matter if the steam generating unit is operated for one hour or 24 hours in any particular steam generating unit operating day. Additionally, all valid hourly emissions data are used in the calculation, whether the "75 percent" criterion is or is not met. Because of these procedures, the operation of the steam generating unit at a low emission rate for 1 hour in a steam generating unit operating day does not get equal weight in offsetting 24 hours of poor performance in another steam generating unit operating day. In summary, the commenter's concerns are valid but the calculation procedure adequately addresses them.

Minimum data capture requirements provide for downtime, but limit the amount of lost data before supplemental sampling is required. The requirements provide the owner or operator

with time to maintain and calibrate the CEMS, correct minor malfunctions, and arrange for supplemental sampling if necessary, while at the same time providing sufficient data for compliance determinations. Minimum data capture requirements also prevent the possibility of an affected facility operating for unreasonably long periods without collecting data. This does not reward operators; the extra cost of supplemental sampling provides incentive to operate the CEMS properly. Well operated and maintained CEMS will routinely operate better than the minimum data requirements and thus supplemental sampling should rarely be required.

4. Comment: Two commenters (IV-D-1, IV-D-86) said sources should not be allowed to arbitrarily exclude any data. They suggested that specific data validation criteria be developed so as to retain control of which data are included or excluded.

Response: Procedure 1 (Appendix F) provides specific criteria for defining when CEMS data are not valid for purposes of meeting the minimum data capture requirements. Sections 60.12 and 60.13 of the General Provisions require continuous operation except for periods of system breakdown, repair, calibration checks, and zero and span adjustment. Section 60.47b provides minimum data capture requirements, and 60.49b requires identification of times when emission data have been excluded and justification for excluding data. As long as the CEMS is not "out of control" as defined by Procedure 1 (Appendix F) and the source is combusting sulfur-bearing fuels, there appear to be few instances when CEMS data can be excluded. The burden of proof is on the operator to justify exclusion of data from average emission rate calculations. If the CEMS is operating, the data are

required to be made available upon request. This appears to provide sufficient authority while allowing enforcement discretion for unforeseen, yet justifiable, reasons.

5. Comment: Two commenters (IV-D-1, IV-D-86) said that if indication of daily averages that are valid due to excess drift were required, reporting of each individual drift calculation would be unnecessary.

Response: This has been examined and appropriate changes have been incorporated in the regulation. There is no need to routinely report daily CEMS drift test results. However, periods when the CEMS is out of control are required to be reported by 60.49b(j)(5).

2.15.4 Performance Testing

1. Comment: One commenter (IV-D-13) noted that nowhere in the proposed regulation does it specifically state that the CEMS data are to be used for the initial or subsequent performance tests. According to the commenter, neither Method 19 nor 19A specifies a method for measuring the SO₂ concentration in the stack. The commenter said the subpart should explicitly stipulate how the source should obtain these values for determining compliance.

Response: This has been clarified in the final standard, which requires an initial 30-day performance test to be conducted using the CEMS or alternative monitoring procedures under Method 19.

2. Comment: One commenter (IV-D-13) said that if the CEMS values are to be used in the initial performance test, then the Performance Specification Test should be conducted and

accepted prior to the initial performance test. The commenter stated that this must be stipulated in the subpart, because the General Provisions require the CEMS performance evaluations to be conducted during or within 30 days after the initial performance test.

Response: The final standard stipulates that the CEMS Performance Specification test must be conducted prior to the initial performance test of the SO₂ control system.

2.15.5 Startup, Shutdown, and Malfunction

1. Comment: Several commenters (IV-D-21, IV-D-23, IV-D-26, IV-D-44, IV-D-55, IV-D-56, IV-D-57, IV-D-58, IV-D-62, IV-D-66, IV-D-73, IV-D-74, IV-D-79, IV-D-84, IV-D-85, IV-F-1.7) felt that emissions during startup, shutdown, and malfunction should not be included when determining compliance with percent reduction requirements. They said a 30-day rolling average does not provide sufficient allowance for these periods with current FGD system reliabilities and the uncertainty of availability of very low sulfur fuels, and the costs of maintaining a backup compliance system are prohibitive and unrealistic.

Response: Emissions from industrial-commercial-institutional steam generating units during periods of startup, shutdown, and malfunction can be significant. In addition, a review of the factors affecting FGD performance indicates that SO₂ removal efficiency can be maintained at high levels even during periods of startup and shutdown. Therefore, there generally should be no need, beyond conventional practice (such as firing natural gas during startup of a coal-fired steam generating unit for ignition purposes), for firing

alternative fuels during periods of startup and shutdown. Overall, the 30-day averaging time is long enough to "dampen out" any slight variations in short-term SO₂ control technology performance during these periods. During periods of FGD system malfunction, however, some type of alternative compliance procedure may be necessary to maintain compliance with the standards on a 30-day rolling average basis. The costs of various alternative compliance procedures (maintaining a spare scrubber module or firing natural gas or very low sulfur oil) were examined and found to be reasonable. Therefore, emissions during periods of startup, shutdown, and malfunction are not exempt from compliance with the standards.

2. Comment: Five commenters (IV-D-58, IV-D-62, IV-D-66, IV-D-74, IV-D-84) said that by requiring the burning of an alternative fuel such as natural gas during periods of startup, shutdown, and malfunction, the standard appears to be in contravention of Section 111. They claimed the requirement for "continuous" emission reduction has been interpreted by the courts as likely banning intermittent controls, including the temporary use of low sulfur fuels.

Response: Flue gas desulfurization, supplemented by low sulfur fuels, constitutes a system of continuous emission reduction. Indeed, it is more continuous than FGD alone, since the low sulfur fuels minimize emission peaks during startup, shutdown, or malfunction of the FGD system. The requirement that NSPS reflect "continuous" systems was meant to avoid "intermittent" control systems, which reduce emissions only when atmospheric dispersion conditions are poor [H. R. Rep. No. 294, 95th Cong., 1st Sess. 81-92 (1977)]. The

requirement was not intended to prevent the inclusion in an NSPS of systems that minimize emissions during startup, shutdown or malfunction.

2.15.6 Miscellaneous Monitoring Comments

1. Comment: One commenter (IV-D-20) said that under the alternative to CEMS, fuel sampling and analysis, specified in 40 CFR 60.47b(b)(1), the requirement for daily fuel oil samples is unnecessary for affected facilities firing fuel oil from homogeneous storage tank mixtures. The commenter stated that upon receipt of additional fuel oil shipments, it would then be appropriate to require additional fuel oil samples and analyses.

Response: The requirement that samples of fuel oil be analyzed daily for sulfur content has been retained for two reasons. First, in many large manufacturing facilities, multiple oil storage tanks feeding into the same fuel lines could result in a mixture of oils with different sulfur contents being fired in the steam generating unit. Second, fuel oil placed in storage prior to being fired can mix with fuel oil from prior or subsequent shipments (or stratify, depending on tank design) and result in a change in the sulfur content of the fuel oil being fired. For these reasons, continuous compliance with the SO₂ emission limits could not be determined accurately without daily analyses of the sulfur content of fuel oil fired in a steam generating unit. Daily sampling and analysis of oil sulfur content is uncomplicated and not time consuming, and should not represent a significant burden to steam generating unit operators.

As a result of refining, however, low sulfur fuel oils show very little variability in heating value. Data obtained from one electric utility plant, for example, show that the heating value (J/kg; Btu/lb) of the fuel oil received at the plant over a 77-day period, comprising four separate shipments of fuel oil, varied by less than one-half of 1 percent. Because the variability in the heating value of low sulfur fuel oil is negligible, the final regulation allows the use of a single heating value in calculating the 30-day rolling average emission rates for each calendar quarter for such oil. The final regulation requires owners or operators of oil-fired steam generating units to determine the heating value of the fuel oil sampled during the first steam generating unit operating day in each calendar month. The lowest of the three heating values obtained during each calendar quarter is used to calculate all of the SO₂ emission rates for the calendar quarter. If a steam generating unit operator believes that, for some reason, the first steam generating unit operating day was not representative of the fuel fired for the remainder of the calendar month, more frequent measurement of the heating value may be conducted.

2. Comment: One commenter (IV-D-72) said that bi-weekly testing of EPA reference samples and splitting additional fuel samples with independent laboratories as a quality assurance procedure when performing fuel sampling and analysis is excessive. The commenter asserted that split samples for quality assurance should be conducted monthly, and reference samples should be analyzed quarterly.

Response: The requirements mentioned by the commenter are not included in either the proposed or promulgated standards.

2.15.7 Recordkeeping and Reporting

1. Comment: Two commenters (IV-D-1, IV-D-86) said all data collected by the CEMS should be required to be recorded, to provide a convenient record of CEMS activity, even if some of the data are not required to be reported.

Response: A requirement that all data collected by the CEMS be recorded and retained for 2 years has been included in the final standard.

2. Comment: Four commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53) said the sheer complexity of some of the reporting requirements will make it difficult to obtain accurate calculations. For example, the commenters said, when burning mixed fuels, the proper "F" factors have to be determined based on a complex set of operating variables. They claimed that having to calculate all these variables will unnecessarily contribute to less accurate and less meaningful data.

Response: The reporting and calculation requirements reflect only the information necessary to determine that the CEMS is operating properly and the unit is in compliance. The requirements are clearly described in the regulation and in Method 19 and efforts have been made to keep them as uncomplicated as possible.

3. Comment: Four commenters (IV-D-26, IV-D-30, IV-D-50, IV-D-53) said the time that will be required for other agencies to review the reported data was not considered. They said past experience indicates that State agencies are inadequately staffed to cope with the volume and sophistication of the information which would be provided.

Response: In developing the reporting and recordkeeping requirements associated with these standards, the burden associated with review of the reports by enforcement personnel was assessed. This burden, which may be assumed by Federal, State, or local enforcement personnel, was determined to be reasonable and, therefore, submittal of reports from steam generating unit operators is required. If State or local enforcement officials find these burdens to be too high, given specific State or local circumstances, they may elect not to request delegation of authority from the Federal government to administer and enforce this NSPS.

2.16 MISCELLANEOUS COMMENTS

1. Comment: One commenter (IV-D-9) felt that the proposed effective date of the standard (June 19, 1986) is too restrictive. According to the commenter, most projects of this size take from 9 to 18 months to design and it would force a massive redesign if the percent reduction requirement were made retroactive. The commenter suggested that the effective date be revised to 6 months after promulgation of the final standard.

Response: Section 111(a)(2) defines the "new sources" subject to an NSPS to be those built (i.e., on which construction commences) after the NSPS is proposed. This does not impose retroactive requirements or require redesign of sources. The notice of proposed rulemaking put potential owners and operators of sources to be built thereafter on notice that those sources would be subject to the NSPS. See Denial of Petitions for Reconsideration of Final [Utility Boiler NSPS] Regulations, 45 FR 8210, 8232-8233 (Feb. 6, 1980).

2. Comment: Two commenters (IV-D-55, IV-D-56) said the failure to promulgate the revision to the source category list to include nonfossil fuel-fired steam generating units and commercial and institutional steam generating units before proposing the standards is in violation of the procedure required by the Clean Air Act. The commenter asserted the Agency should first complete the rulemaking regarding the list of source categories and then repropose a standard.

Response: Section 111(b) requires the Agency to list, and set NSPS for, "categories of stationary sources...[that] cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." These source categories are referred to as "significant contributors" [National Asphalt Pavement Ass'n v. Train, 539 F. 2d 775 (D.C. Cir. 1976)]. Section 111(f) required the Agency to add all "major" source categories that are significant contributors to the Section 111(b) list, and to set NSPS for them by August 7, 1982. A "major" source is one that emits more than 100 tons per year of any air pollutant [Section 302(j)].

In 1971, the Agency listed and set NSPS for fossil fuel steam generating units of more than 250 million Btu/hour heat input [36 FR 5931 (March 31, 1971)]. In 1979, the category of fossil fuel industrial steam generating units (without regard to heat input rate) was added to the priority list [44 FR 49222 (Aug. 21, 1979)]. In 1984, it was concluded that this latter source category should be broadened to include commercial, institutional and nonfossil fuel steam generating units. This conclusion was based on the determination that the design, emission rates, and

applicable control techniques for fossil, nonfossil and mixed fuel steam generating units were substantially similar:

In fact, any practical difference between fossil and nonfossil fuel-fired boilers has virtually disappeared as many new boilers have interchangeable fossil fuel, nonfossil fuel and mixed fuel capability [49 FR 25156 (June 19, 1984)].

In addition, commercial and institutional steam generating units were found to be substantially similar to industrial steam generating units:

These boilers emit similar pollutants, fire the same fuels, and may enjoy the same emission control techniques. Their impacts on human health and welfare are similar... [*Id.*].

The Agency therefore proposed to broaden the source category to include commercial, institutional and nonfossil fuel steam generating units, and simultaneously proposed NSPS (controlling emissions of PM and NO_x) for the broadened source category [49 FR 25102 (June 19, 1984)]. Final action was taken on both proposals simultaneously, broadening the source category as proposed, and promulgating an NSPS for the broadened source category [51 FR 42794, 42768 (Nov. 25, 1986)]. The final NSPS, controlling SO₂ emissions, also applies to the broadened source category.

There is no requirement to conduct multiple consecutive rulemakings, the first to determine the scope of the source category, and later ones to determine the terms of the NSPS [*National Asphalt Pavement Ass'n v. Train*, 539 F. 2d 775 (D.C. Cir. 1976)]. In *National Asphalt*, a single rulemaking

was conducted to consider both listing a source category and setting an NSPS for that source category. The Court upheld that procedure:

Thus, the EPA can continue to have one informal rulemaking proceeding as long as that proceeding considers both the "significant contributor" designation and the proposed standards. Indeed, in rulemaking proceedings such as this one, where the data underlying the "significant contributor" designation is likely to overlap substantially with that underlying the proposed standards, the most sensible course for an agency is to have one proceeding directed at both issues [539 F. 2d at 779 n.2. Accord, Thomas v. State of New York, 802 F. 2d 1443, 1443, 1446, 1447 (D.C. Cir. 1986)].

The addition of subsection (f) to Section 111 by the 1977 Amendments to the Act does not change the result. Subsection (f) simply requires the Agency to list by regulation major source categories that are significant contributors, and to set NSPS for them. The legislative history shows that the purpose of subsection (f) was simply to expedite the setting of NSPS for these source categories [H.R. Rep. No. 294, 95th Cong., 1st Sess. 193-195 (1977)]. Neither the text nor the legislative history of subsection (f) suggests that National Asphalt was being overruled, or that EPA was barred from acting on listing a category and setting NSPS for it simultaneously.

In addition, when it was able to propose broadening the source category and propose an NSPS for it in 1984, the Agency was already in default of the statutory requirement that the NSPS be promulgated by 1982. See Sierra Club, supra. If EPA had further delayed the NSPS rulemaking while it first completed a separate listing rulemaking, that would have worsened the Agency's violation of the statutory deadline.

The rulemaking notices proposing the broadening of the source category and proposing NSPS have been clear and have given commenters full and fair opportunity to comment.